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COAL BLENDING IN ILLINOIS

by

Michael L. Wilkey and Charles M. Macal

ARGONNE NATIONAL LABORATORY

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Energy and Environmental Systems Division

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ABSTRACT

Most of the metropolitan areas in the United States are now governed by state-enacted air pollution control regulations that have either prohibited coal burning or have limited it to low sulfur coal. This research studies the economic and operational feasibility of mixing high sulfur Illinois coal with low sulfur Western coal to achieve a blend that can be utilized in maintaining compliance with the sulfur dioxide (SO_2) emission regulations.

Acceptance of the blending option could result in lower coal expenditures, depending on transportation and mine-mouth costs, plus the operational costs involved in the blending procedure.

Various blending facility locations were considered. The economic feasibility of supplying blended coal to the demand regions was assessed. Under conservative assumptions about Western coal price behavior and present SO_2 emission regulations, potential total annual cost savings to Illinois due to blending are estimated at 4.1% or $11.5 million. Under less conservative assumptions, coal blending offers even higher potential savings.

Examination of the operational feasibility of coal blending, with its promising economic advantages, led to a recommendation for an operational demonstration project.

EXECUTIVE SUMMARY

The Illinois Institute for Environmental Quality is the sponsor of a research project, entitled "Coal Blending in Illinois," conducted by the Energy and Environmental Systems Division of Argonne National Laboratory. The results of the research performed are summarized in this report.

The research comprises an examination of the economic and operational feasibility of mixing high sulfur Illinois coal with low sulfur Western coal to achieve a fuel blend that can be used to maintain compliance with the sulfur dioxide (SO_2) emission regulations.

Regulations restricting SO_2 emissions for existing point and area sources have been established nationwide. In Illinois, the focus of this study, more stringent SO_2 emission regulations exist for the heavily industrialized major metropolitan areas (MMAs) than for the rest of the state. For rural and small to medium-sized urban areas, the SO_2 regulation is set at 6 pounds per million Btu ($lb/10^6$ Btu). However, for 13 counties in the Chicago, Peoria, and St. Louis regions, designated as MMAs, a 1.8 $lb/10^6$ Btu SO_2 emission regulation applies. This stricter regulation in effect rules out the use of the abundant high sulfur Illinois coal in these counties, unless flue gas desulfurization systems (scrubbers) are utilized. Since 1971, when the regulation was implemented, most coal burning facilities have reacted to it by switching to low sulfur Western coal. In many instances, the sulfur content of Western coal is low enough to easily comply with the 1.8 SO_2 regulation. For example, a typical Western coal with .7% sulfur content and a heating value of 9800 Btu/lb releases about 1.4 pounds of SO_2 for every million Btu of heat generated. The question arises as to whether economic gains can be realized by mixing or "blending" the Illinois and Western coals. Appropriate proportions of the two coals can be mixed into a blend that would comply with the 1.8 SO_2 emission regulation.

Illinois mines, because of proximity, can ship coal to markets within the state at a much lower cost than Western mines can. Hence, coal blending could result in lower coal expenditures for the state, depending on the relative transportation and mine-mouth costs of both coals, plus the cost of the blending operation. The associated increase in Illinois coal production would also have a favorable impact on the state's economy.

This project is particularly focused on determining the economic and operational feasibility of using blended coal as an alternative fuel for the less-than-utility-sized users ($< 250 \cdot 10^6$ Btu/hr) in the MMAs, where strict SO_2 emission regulations apply. Because of their relatively low consumption (i.e., demand), they are unable to negotiate the economically advantageous long-term, high-tonnage contracts granted to the utility-sized users, and are often forced to buy coal in the "spot" market at much higher prices.

To attain economic feasibility, the delivered price of blended coal must be less than that of Western coal. Components of both prices include the mine-mouth price of coal and the shipping cost to delivery point. The shipping cost of blended coal is further subdivided into cost of delivery from mine to blending facility to the user. The total cost of blending coal includes the capital costs of building a large blending facility and annual operating and maintenance costs.

Blending costs were estimated for facilities in three annual size ranges: less than one million tons; one to four million tons; and four to eight million tons. The most-likely and the worst-case estimates of capital and operating/maintenance costs were calculated for each size range. To arrive at a unit cost per ton for blending, capitalization figures were multiplied by a capital recovery factor determined by amortizing the costs over 20 years at 10% interest for the most-likely case and at 15% for the worst case. Operating/maintenance and capitalization costs were totaled and divided by annual tonnage. The worst case was used only for comparative purposes to determine the sensitivity of savings to fluctuations of the blending costs.

Additionally, different SO_2 emission regulations were investigated to ascertain the effects on the economic feasibility of coal blending. A blending equation was developed, capable of determining the proper proportions of Illinois and Western coals, given the heating value and percent sulfur rating of each coal and the SO_2 emission regulation. A data base was developed by compiling heating values (Btu/lb), sulfur content (% S), and delivered cost of coal shipped from 30 different Western mines and 24 Illinois mines.

Five potential sites for blending facilities were selected, based on their location near transportation lines and proximity to the MMA demand areas. The delivered cost of coal shipped to each site was derived from the mine-mouth prices in the data base and railroad and barge mileage rates. The total price of any blended coal at each facility was computed, using the costs of the constituent coals and the blending proportions equation. Delivered prices to the MMAs were computed for coal from the blending facilities by adding shipping charges.

The first step in the analysis procedure was to determine the minimum cost of supplying all MMAs directly with Western coal only. Next, the coal blending option was considered. The least cost of supplying all the MMA demands with blended and/or Western coal was determined. A subsequent comparison of these two minimum cost figures indicated the cost savings that could be realized due to the utilization of blended coal.

Research conclusions indicate that savings can be realized in the total MMA coal expenditures by using blended coal under various assumptions regarding future behavior of Western coal prices. Under conservative assumptions and the present SO_2 regulation of 1.8 $lb/10^6$ Btu, total annual cost savings due to blending for the MMAs were estimated at 4.1%, or $11.5 million; for assumptions of increasing Western coal prices relative to Illinois prices, total cost savings amounted to 12.9%, or $60.3 million. In all cases, as the SO_2 regulation was relaxed, greater savings were possible. At the SO_2 regulation of 2.5 $lb/10^6$ Btu, estimated cost savings ran between 5.5% and 20.8%, depending on future Western coal price assumptions. Finally, savings due to blending were realized even when higher (worst-case) estimates of capitalization and annual operating/maintenance costs were considered.

Utilization of Illinois coal increased from 1.5 to 2.5 million tons per year under the present 1.8 SO_2 emission regulation and under various assumptions of future Western coal price behavior. Should the regulation be relaxed to 2.5 lb $SO_2/10^6$ Btu, the potential amount of Illinois coal utilized in blending could be as great as 5.5 million tons per year.

Recommendation is made that an operational demonstration project be initiated to provide the empirical data necessary to validate the operational feasibility of coal blending.

1. INTRODUCTION

The Illinois Institute for Environmental Quality is the sponsor of a research program at the Argonne National Laboratory Energy and Environmental Systems Division, entitled "Coal Blending in Illinois." Coal blending is the process in which two or more coals are combined to obtain a prescribed mixture of the constituent qualities. The blend being assessed in this study is that comprised of high sulfur Illinois coal and low sulfur Western coal.

The main purpose of the project is to examine the feasibility and economics of the resulting blend in meeting the 1.8 lb $SO_2/10^6$ Btu emission regulation within three major metropolitan areas (MMAs) in Illinois -- Chicago, Peoria, and St. Louis. Figure 1 shows the 13 counties they contain. The remaining counties are governed by a 6.0 lb $SO_2/10^6$ Btu regulation.

1.1 SULFUR DIOXIDE EMISSION REGULATIONS

In 1971 when the State of Illinois Air Pollution Control Implementation Plan was proposed, nine areas were designated as MMAs (see Table 1). Of the nine, the three mentioned were selected for the more stringent SO_2 emission regulation. Both regulations govern existing boilers. Any new utility or steam generation plant constructed within the United States with boilers rated at 250 million Btu/hr or more will be under a federal regulation of 1.2 lb $SO_2/10^6$ Btu.

Table 1. Illinois Major Metropolitan Areas (MMAs)

MMA	Counties Included
1. Champaign-Urbana	Champaign
2. Chicago	Cook, Lake, Will, DuPage, McHenry, Kane, Grundy, Kendall, and Kankakee
3. Decatur	Macon
4. Peoria	Peoria and Tazewell
5. Rockford	Winnebago
6. Rock Island-Moline	Rock Island
7. Springfield	Sangamon
8. St. Louis (in Illinois)	Madison and St. Clair
9. Bloomington-Normal	McLean

Source: State of Illinois Air Pollution Control Implementation Plan

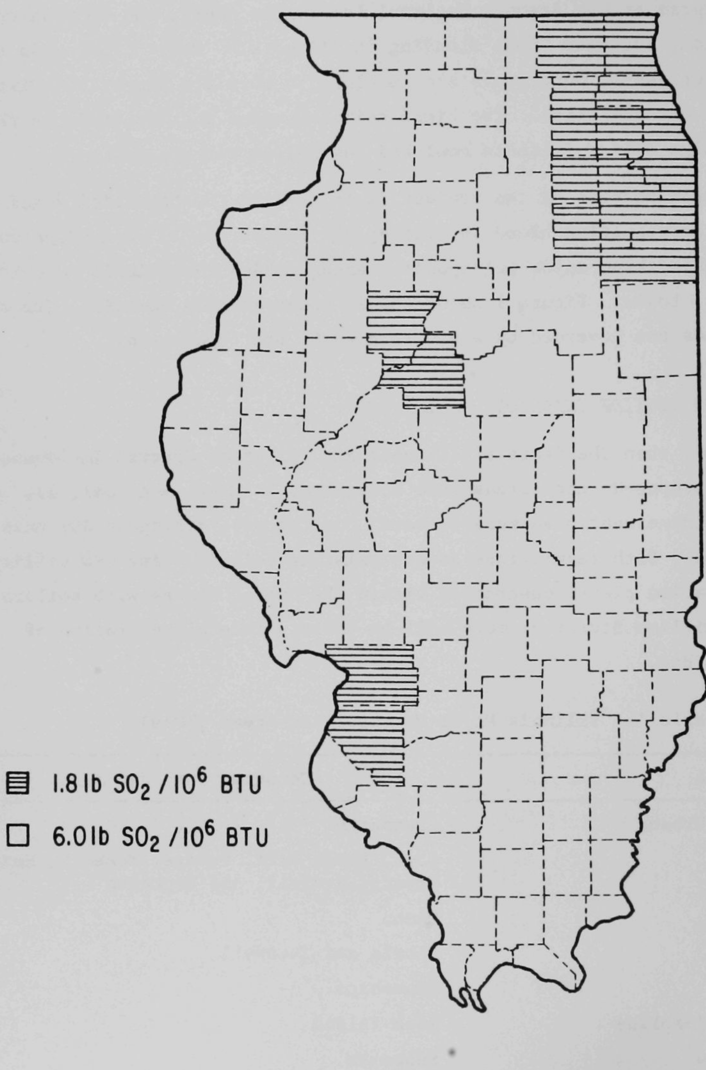


Fig. 1. SO_2 Emission Regulations for Existing Sources in Illinois Counties

Figure 2 shows the total coal tonnages consumed in each county during 1970. The 13 counties contained in the MMAs governed by the 1.8 lb of $SO_2/10^6$ Btu regulation consumed 55% of the state's total in that year. As the regulation implies, the strictest applications are made to those areas in which most of the emissions (i.e., consumption) occur.

Of the adjoining United States, the Illinois regulations are by no means the most lenient, nor the strictest, as the designations shown in Fig. 3 indicate; some are in fact so restrictive that they have in effect ruled out the possibility of using coal at all.

On the other hand, those regulations that permit emissions of only 1% sulfur, or less, and 1.8 lb $SO_2/10^6$ Btu require the burning of low sulfur coal to maintain compliance. Consequently, much demand pressure is being placed on Western coal, which is generally so low in sulfur content that when it is burned SO_2 emission regulations can be met easily. However, although current extraction of low sulfur coal reserves seems adequate to supply the demand, future extraction is now clouded by such matters as the Sierra Club v. Morton lawsuit, the federal coal leasing bill, and the twice-vetoed federal strip mine bill.

1.2 EFFECT OF REGULATIONS ON COAL PRODUCTION

The tremendous rise in demand for the low sulfur Western coal, in the last decade, has been accompanied by higher extraction and transportation costs. Because of the looming legal and federal constraints, plus the uncertainty in the supply end of the market, the delivered price of Western coal will probably continue to rise. Western coal prices of $2.00, and higher, per million Btu are not far into the future for Midwestern coal markets.

While Western coal demand has increased, Illinois coal demand, and hence production, has decreased. In fact, as shown in Fig. 4, production has decreased by about 9% to the 1975 level of 59 million tons. A significant portion of this decrease is attributable to the application of the SO_2 emission regulations in areas where Illinois coal has previously been produced and marketed.

One method to increase Illinois coal production would be to relax the 1.8 lb $SO_2/10^6$ Btu regulation to 5.0 lb $SO_2/10^6$, or beyond; otherwise,

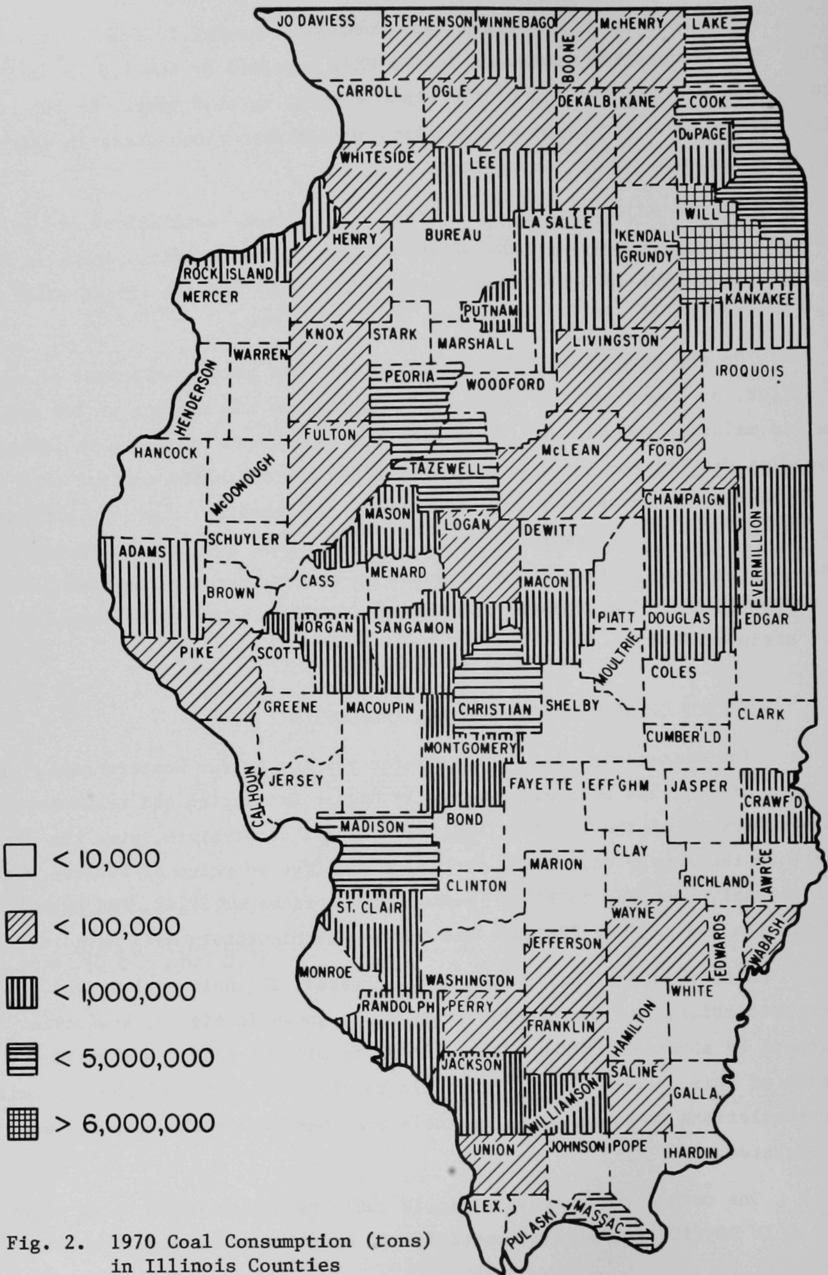
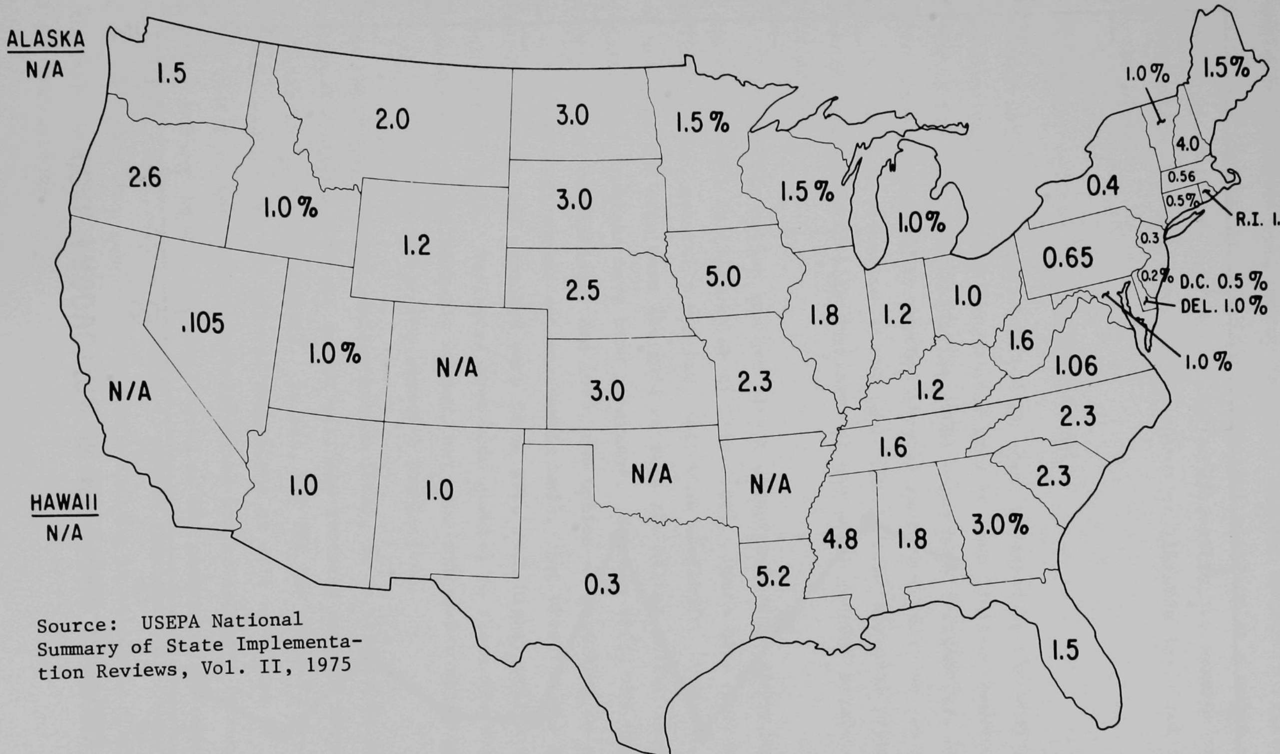


Fig. 2. 1970 Coal Consumption (tons) in Illinois Counties



Source: USEPA National Summary of State Implementation Reviews, Vol. II, 1975

Fig. 3. Most Restrictive SO_2 Emission Regulations for Existing Sources in the U.S. (lb $SO_2/10^6$ Btu or % sulfur by weight)

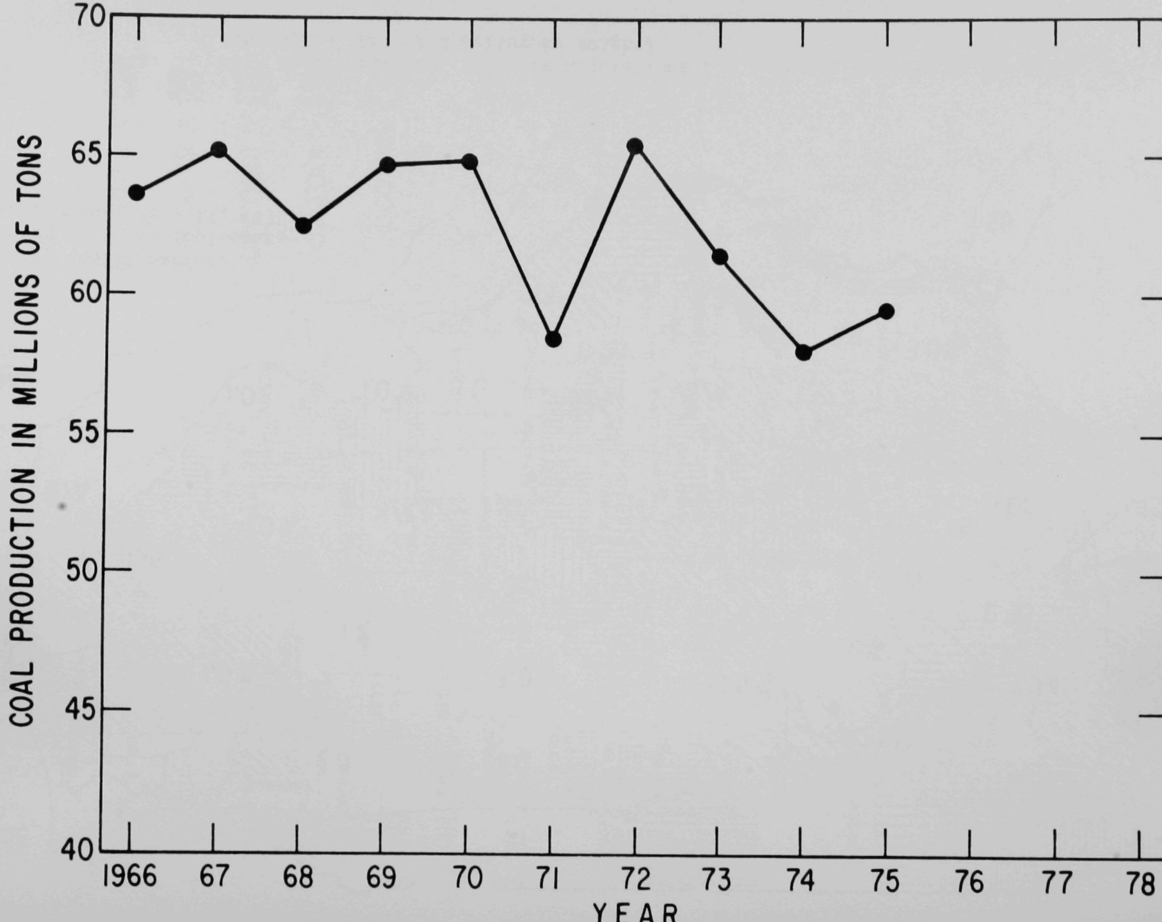


Fig. 4. Illinois Coal Production from 1966 to 1975

most unblended Illinois coal cannot be used. Another method to regain formerly higher levels of production would be to use coal blending as a means of meeting these strict SO_2 emission regulations and, additionally, to examine the effects of the relaxation of regulations on the amount of Illinois coal that can be used in the blend.

1.3 *CURRENT OPTIONS TO MEET REGULATIONS*

Currently, coal users located in areas governed by the most restrictive SO_2 emission regulations have access only to such limited response options as utilizing flue gas desulfurization (FGD) techniques (scrubbers), burning low sulfur coal, switching to another type of fuel (gas/oil), or, as a last resort, operating in violation of the law. Should coal blending prove to be economically and operationally feasible, it may offer another viable option to these users.

The scrubber option has had little acceptance (only three such systems are operational in Illinois as of this date). Users have been willing to burn low sulfur, generally Western, coal when available. However, because boiler units in the area were designed to burn the higher sulfur Illinois coals, some operational problems have been generated. Between 1971, the time of the adoption of these regulations, and 1973, the option of switching to gas or oil as a primary fuel worked out reasonably well. But when the oil shortage hit, many users who had switched were faced with much higher prices and uncertain supplies, or both. Variances have been granted to those who were unable to adapt at once to any workable option, but some coal users still burn Illinois coal in violation of the SO_2 emission regulations.

The Federal Energy Administration (FEA), in an attempt to decrease the national dependence on gas and/or oil, has recently ordered about 40 power plants to burn coal instead. In all, the FEA has about 93 power plants under consideration for the ordered switchover as well as a list of 143 switchover candidates in the major industrial-sized boiler category (greater than 100 million Btu per hour). In the future, as the number of FEA-ordered switchovers increase, coal will be expected to absorb those markets that previously used gas and oil. The compliance of the utilities in switching from gas or oil to coal has placed a greater degree of dependence on low sulfur Western coal and FGD systems.

Most utilities forced to burn low sulfur coal to meet the air emission regulations are able to negotiate long-term, high-tonnage contracts with Western suppliers. The smaller user placed in this category, if able to purchase the coal at all, will have to pay much higher prices. Even if the smaller user is able to negotiate a long-term coal contract, his low consumption will exclude his receiving large volume discounts. When these smaller quantity users cannot negotiate coal contracts, they must rely on "spot markets" where purchases are one-time events.

Because the use of low sulfur coal is the major response to strict SO_2 emission regulations, the approach to determine the economic feasibility of coal blending entails comparison of the costs of supplying Illinois markets with blended coal to the costs of satisfying these markets entirely with Western coal. A demonstration of the feasibility of blending could revive the demand for Illinois coal and thus enhance the position of the state's coal industry. Blending strategies would allow the return to a full production capability of its mines, and the end result would be a boost to the total Illinois economy -- more employed miners and more spin-off jobs related to increased production. In addition, the effects of blending would be to reduce the dependence of utility companies, industries, and steam producers on low sulfur coals, uncertain supplies of expensive imported oils, and rapidly dwindling supplies of natural gas.

1.4 BOILER PROFILE

The number of tons consumed annually in industrial and utility boilers varies from less than one ton to over one million tons. In order to determine the exact composition of the size distribution of boilers within Illinois, three sources were used: the National Emission Data System (NEDS) put out by the U.S. Environmental Protection Agency (EPA); the National Coal Association "Steam Electric Plant Factors" (SEPF) publication; and the preliminary Illinois emission inventory developed by Argonne and updated by the Illinois EPA's Division of Air Pollution Control.

The baseline year for the data was 1970 because in that year the most detailed of the three sources was last updated. The three sources were checked against each other (for 1970 data) to arrive at the final figure for consumption during the baseline year. Consumption was broken down into two types --

individual point source and area source -- that were then added up to give the county total of consumption (see Table 2).

Boilers were ranked from the largest to the smallest number of tons consumed annually, with the cumulative consumption then calculated for each point within the ranking. Figure 5 shows the cumulative percent of the state's total consumption vs. the number of units that consume this amount of coal. This figure shows that within the State of Illinois approximately 90% of the coal consumed is burned by 25% of the units, those largest in size. A boiler rated at 250 x 10^6 Btu/hr, burning at full load, consumes about 100,000 tons of coal/year and ranks as about the 72nd largest boiler. This ranking represents 76% of the state's total consumption. There are 508 boilers within the state that are rated on the basis of annual coal consumption as being below 250 x 10^6 Btu/hr. They represent 88% of the 580 boilers capable of burning coal, a percentage determined from 1970 consumption data.

Table 2. Tons of Bituminous Coal Consumed by County in 1970

County	Point Source Consumption	Area Source Consumption	Total Consumption	% of State's Total Consumption
Adams	89,644	17,730	107,374	.30
Alexander	0	5,190	5,190	.01
Bond	0	3,020	3,020	.01
Boone	36,000	9,350	45,350	.13
Brown	0	1,260	1,260	.00
Bureau	0	8,330	8,330	.02
Calhoun	0	270	270	.00
Carroll	0	4,180	4,180	.01
Cass	0	4,230	4,230	.01
Champaign	159,000	12,760	171,760	.48
Christian	3,007,200	8,000	3,015,200	8.48
Clark	0	3,900	3,900	.01
Clay	0	2,510	2,510	.01
Clinton	4,144	5,160	9,304	.03
Coles	0	7,730	7,730	.02
Cook	3,475,977	1,180,000	4,655,977	13.09
Crawford	505,800	4,280	510,080	1.43
Cumberland	600	1,670	2,270	.01
DeKalb	0	11,420	11,420	.03
DeWitt	0	2,430	2,430	.01
Douglas	422,409	2,910	425,319	1.20
DuPage	83,775	21,200	104,975	.30
Edgar	370	5,300	5,670	.02
Edwards	0	1,400	1,400	.00
Effingham	3,500	4,870	8,370	.02
Fayette	0	3,920	3,920	.01
Ford	28,000	3,270	31,270	.09
Franklin	34,398	18,180	52,578	.15
Fulton	16,888	5,680	22,568	.06
Gallatin	678	1,320	1,998	.01
Greene	0	3,050	3,050	.01
Grundy	55,500	4,170	59,670	.17
Hamilton	74	330	404	.00
Hancock	1,330	4,710	6,040	.02
Hardin	740	2,420	3,160	.01
Henderson	0	870	870	.00
Henry	1,237	11,940	13,177	.04
Iroquois	0	5,980	5,980	.02
Jackson	539,905	12,520	552,425	1.55
Jasper	0	5,980	5,980	.02
Jefferson	13,766	9,370	23,136	.07
Jersey	0	3,130	3,130	.01
Jo Daviess	0	4,150	4,150	.01
Johnson	0	2,460	2,460	.01

Table 2. (Contd.)

County	Point Source Consumption	Area Source Consumption	Total Consumption	% of State's Total Consumption
Kane	46,921	47,770	94,691	.27
Kankakee	123,046	20,260	143,306	.40
Kendall	0	3,500	3,500	.01
Knox	18,349	16,510	34,859	.10
Lake	2,024,486	44,920	2,069,406	5.82
LaSalle	265,958	29,660	295,618	.83
Lawrence	702	4,130	4,832	.01
Lee	438,325	8,110	446,435	1.26
Livingston	9,001	9,500	18,501	.05
Logan	33,809	4,160	37,969	.11
McDonough	0	5,090	5,090	.01
McHenry	1,105	17,030	18,135	.05
Macon	483,089	24,180	507,269	1.43
Macoupin	1,015	7,840	8,855	.02
Madison	2,717,810	61,020	2,778,830	7.81
Marion	150	7,820	7,970	.02
Marshall	0	3,230	3,230	.01
Mason	539,000	2,380	541,380	1.52
Massac	3,541,075	2,410	3,543,485	9.97
Menard	0	1,770	1,770	.00
Mercer	0	2,540	2,540	.01
Monroe	0	2,120	2,120	.01
Montgomery	970,222	5,870	976,092	2.74
Morgan	716,065	6,760	722,825	2.03
Moultrie	0	1,900	1,900	.01
Ogle	48,329	1,001	49,330	.14
Peoria	1,456,390	39,100	1,495,490	4.21
Perry	1,720	8,350	10,070	.03
Piatt	0	1,370	1,370	.00
Pike	11,400	2,910	14,310	.04
Pope	0	1,480	1.480	.00
Pulaski	0	3,320	3,320	.01
Putnam	480,000	740	480,740	1.35
Randolph	815,000	8,540	823,540	2.32
Richland	0	3,100	3,100	.01
Rock Island	182,705	28,200	210,905	.59
St. Clair	387,677	56,410	444,087	1.25
Saline	4,231	9,640	13,871	.04
Sangamon	548,276	20,620	568,896	1.60
Schuyler	0	2,050	2,050	.01
Scott	0	1,270	1,270	.00
Shelby	0	3,770	3,770	.01
Stark	1,295	3,470	4,765	.01
Stephenson	0	13,820	13,820	.04
Tazewell	1,666,073	29,360	1,695,433	4.77
Union	6,000	5,090	11,090	.03

Table 2. (Contd.)

County	Point Source Consumption	Area Source Consumption	Total Consumption	% of State's Total Consumption
Vermilion	531,595	25,040	556,635	1.57
Wabash	60,000	3,830	63,830	.18
Warren	120	1,140	1,260	.00
Washington	250	3,530	3,780	.01
Wayne	35,243	3,640	38,883	.11
White	0	2,560	2,560	.01
Whiteside	5,900	14,370	20,270	.06
Will	6,041,365	45,710	6,087,075	17.12
Williamson	313,515	20,820	334,335	.94
Winnebago	316,489	55,930	372,419	1.05
Woodford	0	3,130	3,130	.01
Grand Total	33,337,279	2,221,981	35,559,260	100.00

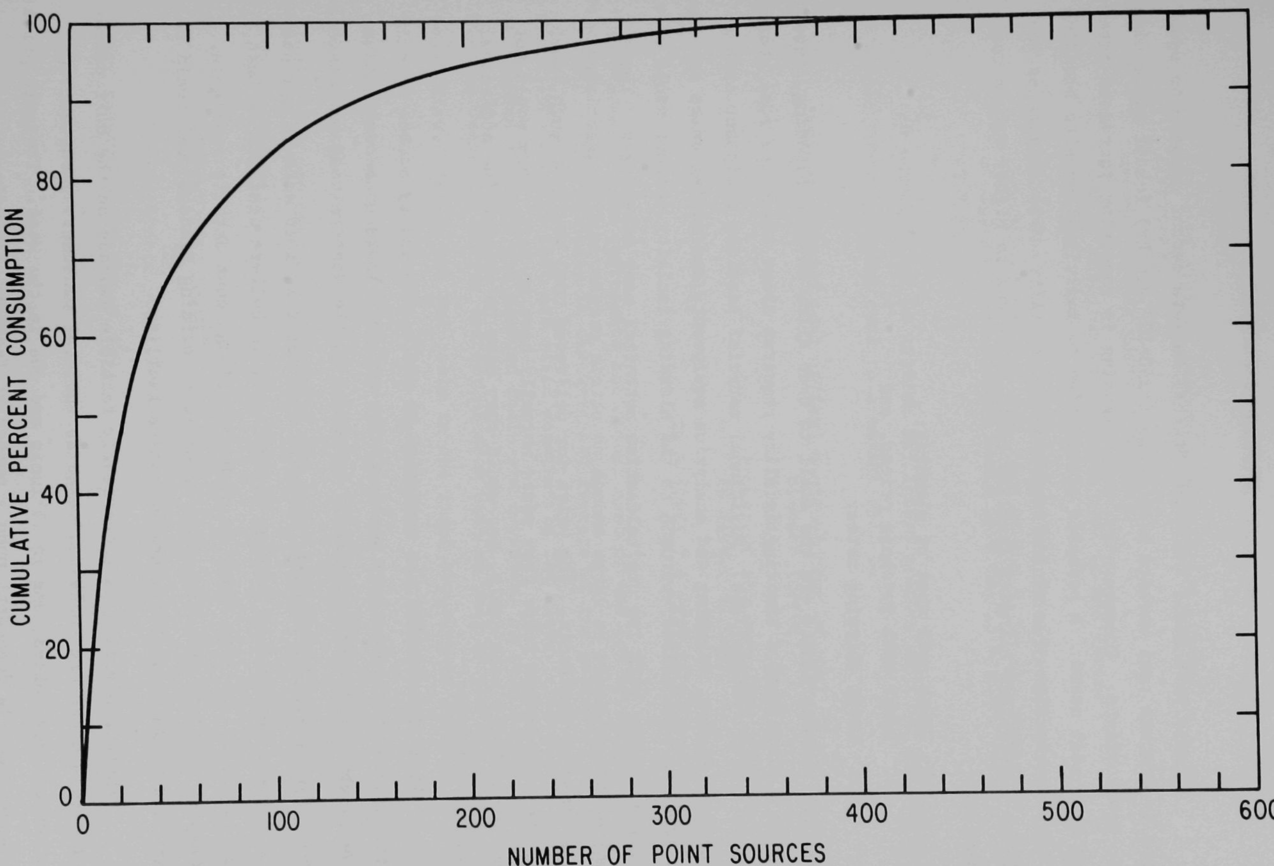


Fig. 5. Cumulative Percent of Illinois Coal Consumption vs. Number of Boilers in 1970

2. *COAL BLENDING ECONOMICS*

Plants with small ($<250 \cdot 10^6$ Btu/hr) boilers cannot compete on equal terms in Western coal markets with large ($>250 \cdot 10^6$ Btu/hr) fossil steam electric power plants. Consequently, coal blending is receiving increased attention from coal users. A probable alternative to individual on-site blending is the construction of a centralized blending facility. The advantages that a large centralized blending facility could offer due to higher volume coal usage are:

1. Lower unit cost of blending,
2. Lower bulk purchase prices, and
3. Lower shipping rates.

Some coal burning plants are too small to even allow on-site blending, inasmuch as a plant with a blending facility requires about twice the coal storage area of a plant without one. Additional material handling equipment such as a conveyor system, weighing and analyzing equipment, and mixing units are also required. A centralized approach to the blending facility concept would offer individual users with low capitalization potential many advantages. Their combined demand could be large enough to obtain prices usually associated with large consumer contracts. The price for delivered coal would be much lower than the spot-market price they would normally have to pay. They would not have to stockpile both coals, nor would they have to procure the additional blending equipment.

It is likely that the economies of scale afforded by access to a centralized blending facility would put the smaller plants on a competitive par with the large quantity utility consumers in the Western coal markets.

The following economic analysis does not take into account any operational costs incurred by burning blended coal in boilers designed to burn Illinois coals. At this time, no such operational cost data is available. As Chapter 8 points out, the costs incurred by burning blended coal could be determined by an operational demonstration facility.

Whether blending is economically feasible depends on the unit prices of blended and Western coals delivered to the coal consumer. Consider two hypothetical coal mines, one in Illinois and one in the West. The unit price of blended coal is dependent upon a number of factors, including:

1. Price of Illinois coal delivered to the blender (PI¢/ton),
2. Price of Western coal delivered to the blender (PW¢/ton),
3. Blender mixing costs (PB¢/ton),
4. Cost of shipping the blended coal to the market (TB¢/ton), and
5. The relative amounts of Western and Illinois coal in a unit ton of blended coal (let f_i and f_w be the fractions of Illinois and Western coals in a ton of blended coal; $f_i + f_w = 1$).

An equation can be written explicitly stating what the delivered cost of a unit ton of blended coal to a market will be:

Cost of blended coal (¢/ton) = actual cost of coal to the blender (¢/ton)
+ blending cost (¢/ton)
+ cost of shipment from blender to market (¢/ton)

or, equivalently,

$$CB = [PW(f_w) + PI(f_i)] + PB + TB$$

The bracketed term represents the actual cost of one ton of coal to the blender. This quantity is the weighted average of the prices of the Western and Illinois coals that are mixed together in the blend. The relative amounts of blended Illinois and Western coals are dependent on such factors as the heating value and sulfur content of each coal as well as the SO_2 emission regulation. Mixing the two coals in the right proportions assures that the blended coal will not exceed the SO_2 emission regulations. A further discussion of how the correct mixing proportions are determined is presented in the next chapter. Included in the prices of Illinois and Western coals to the blender are the mine-mouth costs of the coals plus transportation charges from the mines.

2.1 *WESTERN COAL PRICES*

The delivered cost of Western coal shipped directly to the coal consumer comprises the sum of the:

1. Western coal price at the mine (EW¢/ton) and
2. Shipment cost from the mine to the market (TW¢/ton);

that is,

$$\text{Delivered cost of Western coal (¢/ton)} = \text{Western mine-mouth price (¢/ton)} + \text{shipment cost from mine to market (¢/ton)}$$

or, equivalently,

$$CW = EW + TW.$$

2.2 *BLENDING FACILITY COST*

The mixing or blending cost (PB) is a function of the size of the blending facility. Included in this cost are the capitalization and yearly operating and maintenance costs. The unit blending costs for three different-sized ranges of centralized blending facilities are shown in Fig. 6. The cost data of Fig. 6 were based on estimates made by a large utility company that had contemplated building a blending facility. For a facility with a capability of blending 4 million tons annually, the capitalization cost was estimated to be \$15.75 million; the operating cost (not including actual costs of coal to be purchased) was estimated at \$1.05 million. For a facility with a capacity of 8 million tons, capital costs were estimated to be \$26 million, and the operating cost (excluding coal costs) was estimated at \$2 million.

These costs were converted to unit production costs. At an annual interest rate of 10% and a 20-year amortization period, the annual amount to be paid to retire the capital cost for each size of blending facility was determined. The debt retirement and operating costs were added to yield the total annual cost. This total was then divided by the respective tonnage blended to determine the unit PB. As shown in Fig. 6, the unit PB decreases as the blender capacity increases and economies of scale are realized. The unit costs (per ton) of blending were converted to unit costs on a cents per million Btu basis; also shown in Fig. 6. These conversions were done by assuming "average" heating values for the Illinois and Western coals and calculating the Btu per lb of the blended coal.

2.3 *COMPARISON OF COSTS OF BLENDED AND WESTERN COALS*

The following steps were taken in order to compare the delivered cost of blended coal with the delivered cost of Western coal.

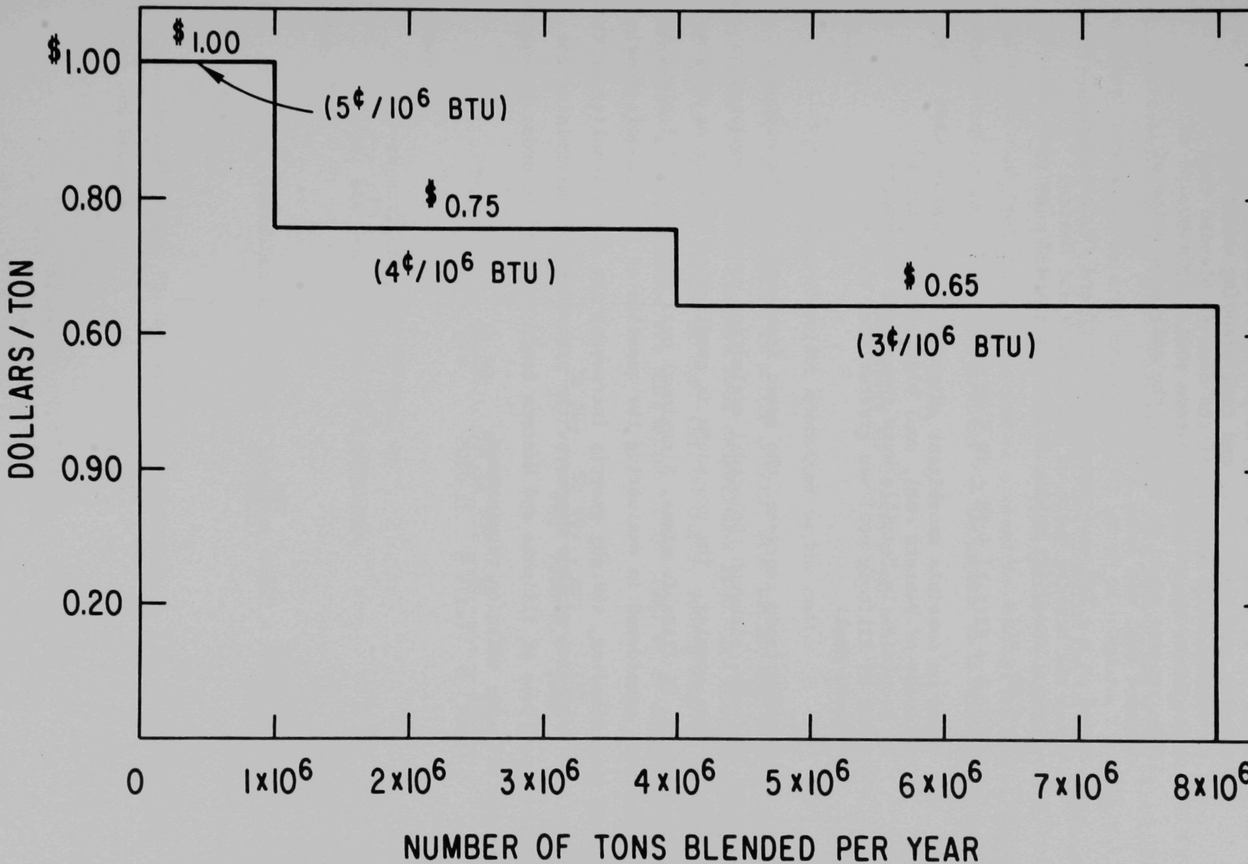


Fig. 6. Cost of Mixing for Various Sizes of Blending Facilities

1. Based on delivered prices, no potential market for blended coal would exist and coal blending would not be economically feasible if the cost of blended coal was greater than that of Western coal: CB > CW. (The reverse would be true if the delivered price of blended coal was lower.)

2. Based on a ¢/10^6 cost conversion of CB and CW, considering the heating value of the blended and Western coals, a potential market exists for blended coal if CB < CW, or:

   $[PW(f_w) + PI(f_i)] + PB + TB < EW + TW.$

3. Based on possible exorbitant shipping costs for delivery of Western coal, coal blending could still be economically feasible even though the mine-mouth price of Illinois coal was greater than that of Western coal.

These comparisons represent the basic framework for the economic feasibility analysis, although the actual evaluation procedure employed in this study is more complex. The procedure is complicated because as many as 30 Western mines, 24 Illinois mines, 5 regional coal markets, and 5 blending facilities were considered in evaluating the question of the economic feasibility of coal blending, thereby greatly increasing the dimensionality of the problem. The following section discusses the procedure for determining the relative proportions of Illinois and Western coals to blend in order to achieve compliance with SO_2 emission regulations.

3. *COAL BLENDING METHODOLOGY*

In this study, we are assuming that the different coals used in the blends combine in a linear relationship. This assumption seems reasonable although empirical data is unavailable to prove or disprove it. The U.S. Environmental Protection Agency publication "Compilation of Air Pollutant Emission Factors" gives an emission factor of 38 lb/ton times percent sulfur for bituminous coal burned in external combustion sources without pollution control equipment. This factor gives the emissions on a "pounds of SO_2 per ton of coal burned" basis.

$$\text{Emissions in } \frac{\text{lb } SO_2}{\text{ton}} = 38S, \tag{1}$$

where

S = the percent sulfur contained in the coal.

To convert this expression to a "lb $SO_2/10^6$ Btu" basis, the norm in which the Illinois SO_2 regulations have been established (see Fig. 1), the divisor is multiplied by 2000 lb/ton of coal (Eq. 2) and by Btu/lb (Eq. 3) and both numerator and denominator are multiplied by 10^6 (Eq. 4) to arrive at Eq. 5 as follows:

$$\text{Emissions in } \frac{\text{lb } SO_2}{\text{lb}} = \frac{\text{lb } SO_2}{\text{ton}} \frac{\text{ton}}{2000 \text{ lb}} = \frac{38S}{2000}, \tag{2}$$

and

$$\text{Emissions in } \frac{\text{lb } SO_2}{\text{Btu}} = \frac{38S \text{ lb } SO_2}{2000 \text{ lb}} \frac{\text{lb}}{H \text{ (Btu)}} = \frac{38S}{H \text{ (2000)}}, \tag{3}$$

where

1 lb coal contains "H" Btu, or

coal has heating value of H (Btu/lb);

and

$$\text{Emissions in } \frac{\text{lb } SO_2}{10^6 \text{ Btu}} = \frac{38S}{H \text{ (2000)}} \times 10^6 = \frac{19000 \text{ (S)}}{\text{(H)}}. \tag{4}$$

In the Illinois MMAs, the SO_2 emission regulation is 1.8 lb $SO_2/10^6$ Btu. Eq. 4 now becomes:

$$\text{Emissions} = 1.8 \frac{\text{lb } SO_2}{10^6 \text{ Btu}} = \frac{19000 \text{ (S)}}{\text{(H)}} \tag{5}$$

In a state like Illinois where the regulation for major metropolitan areas calls for SO_2 emissions less than or equal to 1.8 lb $SO_2/10^6$ Btu of coal burned, the corresponding equation would be:

$$\frac{1.8 \text{ lb } SO_2}{10^6 \text{ Btu}} \geq \frac{19000\ (S)}{(H)} \tag{6}$$

If two types of coal are to be burned (high- and low-sulfur), the fraction of each type of coal in the blend must equal unity:

$$f'_H + f'_L = 1, \text{ or}$$
$$f'_H = 1 - f'_L\ , \tag{7}$$

where

f'_L = fraction of low sulfur coal (heat input basis), and
f'_H = fraction of high sulfur coal (heat input basis).

The emissions of such a blend would have to meet the lb of $SO_2/10^6$ Btu regulations. Equation 8 would yield the SO_2 emission of this blend:

$$\frac{E \text{ lb } SO_2}{10^6} = \left(\frac{19000\ S_H}{H_H}\right) f'_H + \left(\frac{19000\ S_L}{H_L}\right) f'_L\ , \tag{8}$$

where

S_H = % sulfur of high sulfur coal,
S_L = % sulfur of low sulfur coal,
H_H = Btu/lb of high sulfur coal,
H_L = Btu/lb of low sulfur coal, and
E = emission regulation in lb $SO_2/10^6$ Btu.

Equation 8 can be manipulated to give the fraction of each type of coal on a weight basis (Eq. 9): (A more detailed derivation of this equation can be found in Appendix B.)

$$f_H \left(S_H - \frac{E\ H_H}{19000}\right) + f_L \left(S_L - \frac{E\ H_L}{19000}\right) = 0\ , \tag{9}$$

where

f_H = fraction of high sulfur coal (weight basis) and

f_L = fraction of low sulfur coal (weight basis).

The Illinois regulation outside the MMAs (6.0 lb $SO_2/10^6$ Btu) allows "average" Illinois coal (%S = 3.2, 10,800 Btu/lb) to be burned. The current regulation within MMAs (1.8 lb $SO_2/10^6$ Btu/lb) requires for compliance a less than 1% sulfur coal with a heating value of 10,000 Btu/lb; thus effectively ruling out the use of Illinois coal in these areas, unless blending is adopted.

Figure 7 shows the percent of average high sulfur Illinois coal that can be blended with average low sulfur Western coal (% S = 0.5, 9600 Btu/lb) at various SO_2 emission regulations. As an example, a 1.8 lb $SO_2/10^6$ Btu regulation can be met by blending about 16% of "average" Illinois coal with about 84% of "average" Western coal; a 2.8 lb $SO_2/10^6$ Btu regulation can be met with a blend of about 36% Illinois coal and about 64% Western coal.

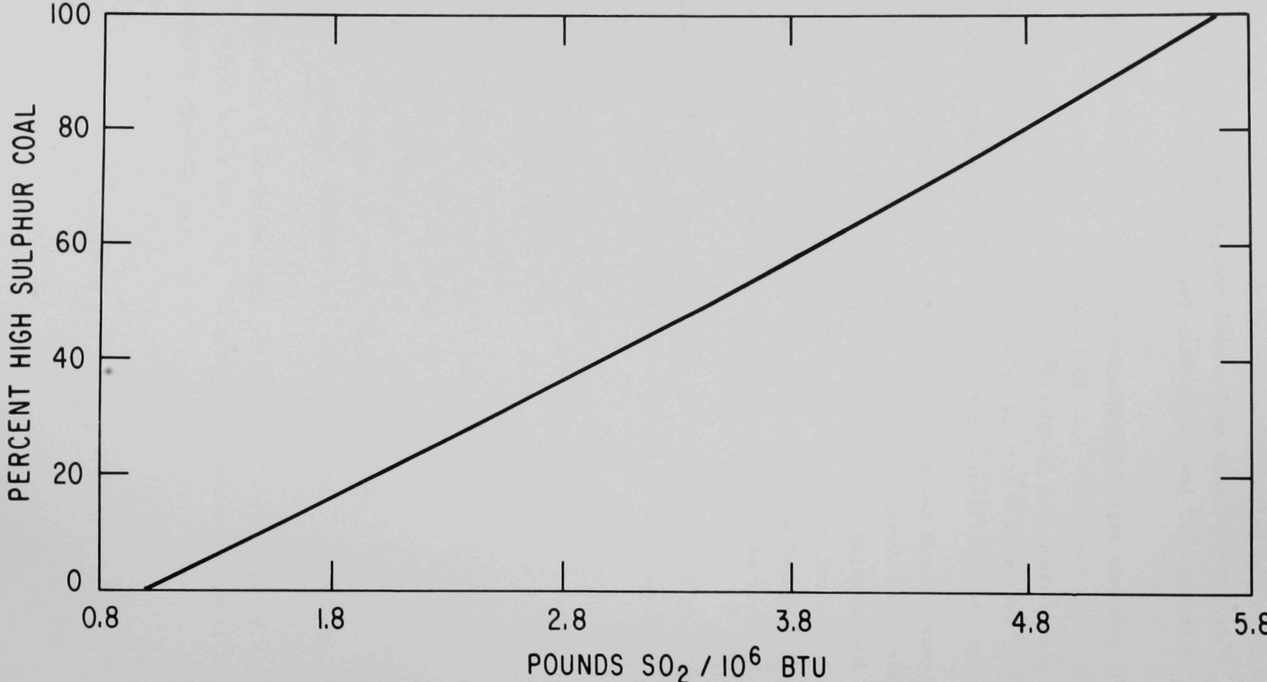


Fig. 7. Percent High Sulfur Coal vs. lb $SO_2/10^6$ Btu Emission Regulations

4. *COAL DATA*

The coal data base used in this study was established in part with information presented in COAL WEEK. This publication lists recent coal deliveries to utilities as reported to the Federal Power Commission. Until recently, the information on coal shipments presented in COAL WEEK itemized the mine source, destination of shipment, shipment size, average Btu/lb, contract type, and delivered price of the coal in ¢/10^6 Btu. Now the percent sulfur and percent ash of the coal are also given. Data were collected on 30 Western mines and 24 Illinois mines. These included every Western and Illinois mine with an annual production in 1974 of more than 100,000 tons for which price information was presented in COAL WEEK, representing over 75% (54 million tons) of Western production as well as over 75% (44 million tons) of Illinois production for that year. (All of the coal data are listed in Appendix B.) Where complete information, such as moisture or sulfur content, was not given on a coal shipment, the *Keystone Coal Industry Manual* (1975 edition) was consulted for representative figures. Yearly mine production totals were also taken from the Keystone manual. Note here that the analysis is somewhat static; only mines presently in operation are included. Consideration of the opening of new mines, or closing of mines currently productive, is beyond the scope of the analysis. However, those that are being considered are deemed to be representative of mines expected to open in the future.

As Tables B.1 and B.2 indicate (see App. B), several readings of Btu/lb and sulfur content, along with price, were recorded for various shipments of coal from each mine. In this study, the coal from each mine was characterized by representative measures of (1) heating value, (2) sulfur content, and (3) mine-mouth price. The representative heating value was established by averaging all the heating value data collected on the mine, as listed in Tables B.1 and B.2. And the representative sulfur content was calculated as the arithmetic mean of all sulfur values collected.

The estimations of mine-mouth prices of coal at each mine were calculated differently. They were established by subtracting transportation charges from delivered prices (taken from COAL WEEK) to the utility, as follows:

$$CE = PD - CT,$$

where

CE = mine-mouth price,

PD = delivered price to the utility (the contract price as stated in COAL WEEK), and

CT = transportation cost from mine to utility.

Since the utility receiving the coal shipment was included in the COAL WEEK data, the transportation cost portion of the price could be estimated. Based on the distance from the mine to the utility, the unit transportation charge was calculated. For railroad shipments, the transportation charge was estimated as:*

$<$ 200 miles CT = (railroad mileage) x 1.75¢/ton-mile,

$<$ 400 miles CT = (railroad mileage) x 1.25¢/ton-mile, and

$\geq$ 400 miles CT = (railroad mileage) x 0.75¢/ton-mile.

For barge shipments, the transportation charge was estimated as (barge mileage) x .53¢/ton-mile. Using the Btu/lb value given along with the coal shipment price, the above transportation cost could be converted from a ¢/ton basis to a ¢/10^6 Btu basis as follows:

$$\text{¢}/10^6 \text{ Btu} = \frac{(\text{¢/ton})\cdot 10^6}{(\text{Btu/lb})\ (2000\ \text{lb/ton})}$$

With this procedure, an estimate of the mine-mouth price of coal could be obtained from the data on every coal shipment, which often meant that several mine-mouth prices could be calculated for the same mine. The highest estimate of a mine-mouth price (excluding spot-price considerations) was assumed to be the most current contract price of the coal for the mine and therefore the most representative.

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*Based on information presented in FEA Project Independence Blueprint Final Task Force Report.

5. *ANALYSIS PROCEDURE*

The coal production-distribution-utilization system under investigation may be conceived of as a large network. Elements of the network include Western coal mines, Illinois coal mines, coal blending facilities, coal consumption regions, and the transportation routes connecting these entities. This system is illustrated in Fig. 8. Evaluating the economic feasibility of coal blending makes certain assumptions necessary concerning the location of coal blending facilities, the aggregation of coal demand into a manageable number of markets for analysis purposes, transportation routes, and coal price-quantity relationships. These assumptions are presented in the following sections.

5.1 *REGIONAL COAL MARKETS*

The 13 counties represented in the three MMAs in Illinois under the 1.8 lb/10^6 Btu SO_2 regulations were aggregated into 5 regional markets. The following table summarizes this aggregation, along with levels of coal consumption for each county in 1970.

Table 3. Regional Coal Market Demands

Market Region	Counties	1970 Coal Consumption (tons)	MMA
I	St. Clair	44,087	St. Louis
	Madison	2,778,830	
II	Peoria	1,495,490	Peoria
	Tazewell	1,695,433	
III	Will	6,087,075	Chicago
	Kankakee	143,306	
	Grundy	59,670	
	Kendall	3,500	
IV	Cook	4,655,977	
	DuPage	104,975	
	Kane	94,691	
V	Lake	2,069,406	
	McHenry	18,135	

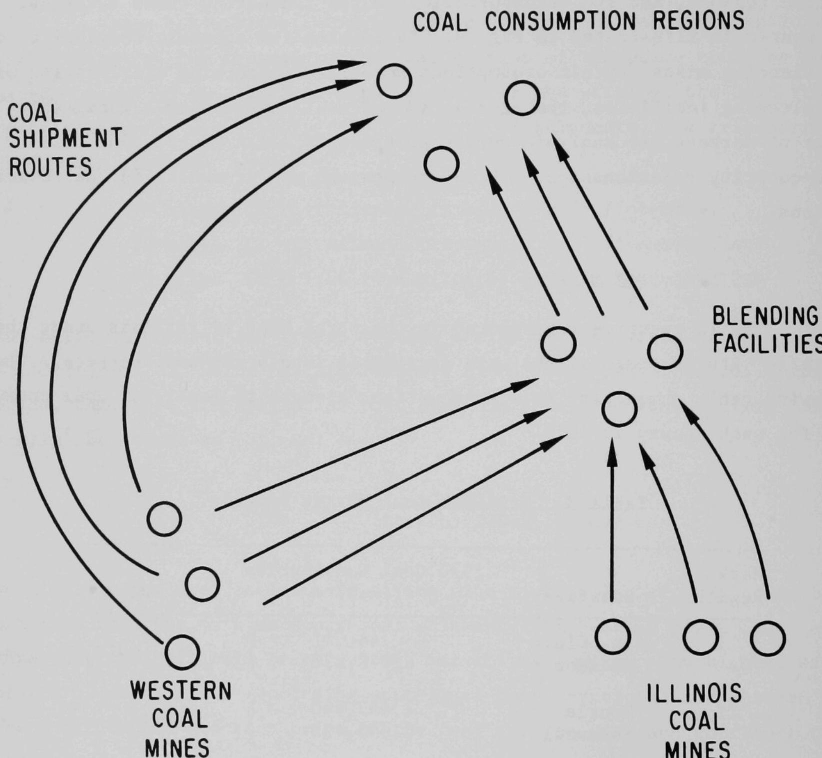

Fig. 8. Coal Supply Network

St. Clair and Madison counties were considered as being in the same market because of their proximity. Peoria and Tazewell counties were considered as Market II for the same reason. Coal consumption and the transportation cost differential were great enough between Chicago MMA counties to assume that regional markets could exist within the Chicago MMA. Markets III, IV, and V consist of several counties, with one of the counties in each region consuming the majority of coal. As Table 3 indicates, Will, Cook, and Lake counties consume more than 95% of the coal demanded in their respective regions.

Although the 1970 coal-consumption figures listed in Table 3 are the latest available, these figures probably overstate current coal consumption. Since the stringent SO_2 emission regulation for MMAs was put into effect in 1971, some coal boilers in these areas have switched to oil or have installed scrubbers while continuing to burn high sulfur Illinois coal.

Data on the capacities of generating plants using scrubbers were obtained. To estimate 1975 Western coal consumption in major metropolitan areas, the capacities of generating plants with scrubbers were subtracted from the regional 1970 coal-consumption figures. No current data were available on the portion of coal-fired generators that had switched from coal to oil since 1971. However, coal consumption was assumed to have been thereby reduced by 20% in each region. Estimates for coal consumption in 1975 are given in Table 4.

Table 4. Regional Coal Demand Estimates

Market Region	1970 Consumption (tons) A	Capacity of Generators with Scrubbers (tons) B	Estimated Coal Consumption, 1975 (tons) (A-B) x .80
I	3,222,917	275,000	2,358,333
II	3,190,923	0	2,552,738
III	6,293,551	122,740	4,936,648
IV	4,855,643	0	3,884,514
V	2,087,541	0	1,670,032
Total	19,650,575	397,740	15,402,265

All of the coal consumption for a particular market was assumed to be located at approximately the demand center of the region. Transportation charges for coal shipped to each region were based on routes terminating at the demand centers.

5.2 BLENDING FACILITY SITES

The economic feasibility of coal blending is largely dependent on the location of such facilities. Coal shipment charges from the mines to the blenders and in turn to the coal consumption regions account for a substantial portion of the price of the coal to the consumer. Five areas in Illinois are considered here as potential locations for coal blending facilities. These are: (1) Alton, (2) Havanna, (3) Peoria, (4) Joliet, and (5) Waukegan. The location of all potential sites is planned to be near water routes, thereby reducing transportation charges. The first four sites listed are located on the Illinois River, the fifth is on Lake Michigan. Four of the blending locations correspond geographically to four of the five regional coal markets. Because of the relative inaccessibility of that area to barge traffic, the Cook County region was not considered as a blending site.

Specific sites for each of the five blending facilities were selected so that transportation distances could be estimated. Transportation charges would not be particularly sensitive to blender locations within small areas. For example, the blender in Market I was assumed to be located at a point just outside of Alton. However, if it was located a few miles up or down the river, transportation charges from the mines to the blender and from it to the regional market would be affected very little. Thus, only general locations for blending facilities are assumed; specific blending sites are not evaluated.

5.3 TRANSPORTATION COSTS

Transportation charges were estimated for coal shipments between the following points:

1. Western mines to regional demand points,
2. Western mines to blending facility sites,
3. Illinois mines to blending facility sites, and
4. Blending facility sites to regional demand points.

Per unit transportation charges were assumed to be based on distances only; rates were not varied along a given route according to the tonnages shipped. Thus, rates for shipment of Western coal to regional demand points and potential blending facility sites were generally based upon the shortest major railroad distance between the particular Western mine and the destination. Railroad mileages were computed from the *Handy Railroad Atlas of the United States*. The graduated railroad rate schedule of 1.75¢/ton-mile for trips of less than 200 miles, 1.25¢/ton-mile for trips of between 200 and 400 miles, and .75¢/ton-mile for trips greater than 400 miles was used in all calculations. In some cases, the cheapest transportation route was a rail-barge route. Barge rates were assumed to be .53¢/ton-mile; again, based on distance only. A transloading charge of 30¢/ton was included in the shipment rate for coal transferred from rail to barge and vice versa.

Few of the least-cost routes from Western mines to destinations included barge shipments. Only Western mines in North Dakota transported shipments down through Lake Michigan. Coal shipments from Illinois mines to blending sites, as well as those from blenders to regional markets, were generally routed by barge down the Illinois River, in the least-cost route formulation, since the blenders were all located along waterways.

5.4 COAL PRICE-QUANTITY RELATIONSHIPS

The supply of Illinois coal was assumed to be elastic over the range of tonnages that could be utilized in coal blending. Another assumption was that all of the 24 major Illinois coal mines considered in the study could increase production up to 33% of their 1974 output without accruing a unit increase in costs -- the price of coal at the mine mouth to remain constant over the 0 to 33% range of increase in Illinois coal production. This premise is warranted considering the depressed nature of the Illinois coal industry, as illustrated in Fig. 4.

The elasticity of the Western coal supply is uncertain, although probably in the range of 0 to 1. (Here, Western coal supply elasticity refers to the percent change in the mine-mouth price of Western coal resulting from the percent increase in production capacity. That is, elasticity = $\%\Delta(¢/\text{ton})/\%\Delta(\text{tons})$.) For this reason, the price elasticity of Western coal was used as a parameter in the analysis procedure. Values of 0 and 1 were considered for

Western coal price elasticity, and the economic feasibility of coal blending was evaluated under each of the price elasticity assumptions. In this way, the costs of importing Western coal to Illinois could be estimated within a range, depending on the actual elasticity of Western coal. The assumption was made that Western coal mines also could increase yearly coal production up to a maximum of 33% of their 1974 output.

The possibilities were also considered that the price of Western coal could increase substantially with increases in production costs or increases in demand for Western coal originating in areas outside of Illinois. A parameter termed the "Western price multiplier" was used to determine how the economic feasibility of coal blending varied with shifts in Western coal prices. Three values of the Western price multiplier were selected corresponding to increases in the mine-mouth Western coal prices of 0%, 50%, and 100%. In effect, on successive scenarios, the mine-mouth price of coal determined for each Western mine was multiplied respectively by 1, 1.5, and 2, and the economic feasibility of coal blending was then determined in each situation.

For the Western price elasticity assumption of 0, three scenarios could be generated based on the three values (1, 1.5, and 2) for the Western price multiplier. For the price elasticity assumption of 1, three more scenarios could be generated for the various price multiplier values. In all, six scenarios could be generated for a given SO_2 emission regulation, each with different assumptions about Western coal price behavior. The chances would be least for coal blending to be economically feasible at a Western price elasticity of 0 and a Western price multiplier of 1. Any increase in these two parameters increases the relative price of Western to Illinois coal, thereby improving the chances for blended coal to become economically more desirable than Western. Therefore, the chances would be greatest for coal blending to be economically feasible at maximum values of the Western coal parameters -- that is, when Western price elasticity is 1 and the Western price multiplier is 2.

5.5 *LEAST-COST OBJECTIVE*

The first step in the economic feasibility evaluation consists of determining the unit delivered costs of blended and Western coals to each of the regional markets. Using the equation developed on page 22, the unit costs of delivering coal from each Western mine directly to the regional markets were determined. Using the equation developed on page 21, the delivered costs per ton of blended coal were calculated for every combination of Western and Illinois mines through all blending sites to all markets. Blended coal delivered costs are based on combining Illinois and Western coals in the proportions given by Eq. 9. Any Western coal that was unable to meet the SO_2 emission regulations was not considered as a candidate for blending. Therefore, it is theoretically assumed that every ton of blended coal would meet them. Each regional market then is faced with a total of 3630* delivered prices, upon which coal purchasing decisions are made.

The market's objective is to minimize total coal expenditures by successively choosing coal at the next lowest marginal delivered cost, until the quantity demanded by the market has been met. A market purchases enough coal to satisfy the demand of the region. The lowest delivered price (on a ¢/10^6 Btu basis) is selected from the array of market prices and is purchased first. Coal of this type (whether blended or Western) is purchased up to the production-limit point of the mine, or the point at which its unit coal production costs surpass the next lowest delivered price.

If the delivered price of the next million Btu of blended coal is less than it is for the same quantity of Western coal, then coal blending is economically feasible. A result of the coal selection procedure would be the determination of the quantities of blended coal that could be supported by each market. Quite possibly a given market could most economically satisfy its coal consumption needs through a combination of shipments made directly from Western mines and those from several coal blending facilities.

The coal purchasing procedure described above models a decision process involving a single regional market. For multiple markets, the situation is more complex. Within a market, the minimum cost objective is plausible. However, a situation may arise in which the same coal can be supplied to several markets at the minimum price within each of the markets; an allocation problem then exists.

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*If W equals the number of Western mines, I equals the number of Illinois mines, and B is the number of blending sites, then each market is faced with $W + W \cdot I \cdot B$ coal prices upon which it bases its coal purchasing decisions. Here, W equals 30, I equals 24, and B equals 5. Thus, each market is faced with 3630 prices.

In this study, the procedure used to resolve that problem is to follow a least-cost rule in allocating coal among markets. If two or more markets are competing for the same coal, it is presumed to be sent to the market that has the lowest delivered cost. Thus, the procedure assumes a least-cost objective in coal expenditures for the state as a whole as well as regionally.

In summary, the problem of determining the economic feasibility of coal blending reduces to solving the problem:

Minimize (total cost of coal to MMA markets
with stringent SO_2 emissions regulations);

subject to the constraints:

1. Coal mine capacities are increased by no more than 33%.
2. Western and Illinois coals are blended in such proportions that SO_2 emission regulations are met.
3. The coal demand in each region is met.

Solution of this problem provides information on:

1. Quantities of coal blended at each blending facility.
2. Coal costs by region and state.
3. Quantities of coal provided by each coal mine.

A more complete mathematical description of the problem formulation is given in Appendix C.

5.6 SCENARIO BASIS

As stated previously, generating various scenarios based on different assumptions about the future price of Western coal could be useful. Important policy questions can be asked concerning the effect that SO_2 regulations have upon the economic feasibility of coal blending. Therefore, its feasibility was determined for three SO_2 regulations.

1. The present regulation of 1.8 lb $SO_2/10^6$ Btu.
2. 2.0 lb $SO_2/10^6$ Btu.
3. 2.5 lb $SO_2/10^6$ Btu.

In all, three parameters in this study were varied. Three values for the SO_2 regulations, two values for the Western price elasticities, and three values for the Western price multipliers. A total of 18 scenarios were generated to test coal blending feasibility. (For comparative purposes, several other scenarios were generated in which coal blending was not considered.) Costs were computed for satisfying coal demands of the MMAs solely with Western coal. The cost savings due to blending could be evaluated by comparing the cost of satisfying the demand using only Western coal with the cost of satisfying the same demand using the blended coal option. The results of these scenarios are summarized in the next section.

6. *ANALYSIS OF RESULTS*

The results of 18 scenarios in which coal blending was considered as a substitute for Western coal utilization are illustrated in Table 5. The SO_2 regulation, Western coal price elasticity, and the Western price multiplier were varied among scenarios as shown. For each scenario, the total tons of Illinois coal utilized are given, along with the total coal costs, for the three MMAs considered. Each scenario produces estimates of the capacities of the coal blending facilities, as shown in the table.* The last column in Table 5 lists the portion of blended coal supplied to the MMA, the rest of the coal being supplied directly from Western mines. All of the results are obtained using the criterion that the system operates at least-cost.

For comparative purposes, higher capitalization, interest and annual operating costs for the three blending facility sizes were used. These higher costs result in the following increases in the cost-per-ton charges for blending. The cost for a less-than-million-ton per year blender size increased to \$3.00/ton (200% increase); the one-to-four-million-ton, to \$1.98/ton (164% increase); and the largest, or four-to-eight-million-ton, to \$1.08/ton (66% increase). These extreme blending facility costs were used in Scenarios 1, 2, 3 and 16, 17, 18, the least and most advantageous situations for blending, respectively. These drastic increases in the blending costs reduced the former savings due to blending by only 2 to 3%. Hence the savings do not appear to be very sensitive to fluctuations in the blending costs.

As Fig. 9 illustrates, the amount of Illinois coal blended increases as the SO_2 regulations are relaxed. For a higher regulation, a greater portion of Illinois coal can be used in blending without exceeding the emission regulation. At the present SO_2 regulation of 1.8 lb $SO_2/10^6$ Btu, a total of between 1.56 and 2.45 million tons of Illinois coal can be blended economically, depending upon assumptions made about the behavior of Western coal prices. The figure of 1.56 million tons (Scenario 1) is based on assumptions that present Western coal prices will remain at their present level and that Western

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*Preliminary results indicated that due to its location within the MMA, the Peoria blending facility was able to dominate the Peoria market to the extent that the amount of coal blended at the Havanna site was insignificant. Therefore, the Havanna site was eliminated from consideration.

Table 5. Scenario Results

Scenario	SO_2 Regulation ($lb/10^6$ Btu)	Western Coal Elasticity	Western Price Multiplier	Illinois Tons Utilized (M/yr)	Total Cost of Coal to MMA ($M/yr)	Blender Capacities (M of Tons/yr) Alton	Peoria	Will	Lake	% of MMA Coal Demand Satisfied By Blended Coal
1	1.8	0	1	1.56	268	0	1.47	5.82	1.67	58
2	2.0	0	1	1.99	266	0	2.88	4.47	1.67	59
3	2.5	0	1	2.86	252	0	2.87	3.67	1.67	53
4	1.8	1	1	1.80	290	0	2.30	6.32	1.67	67
5	2.0	1	1	2.52	284	0	3.32	6.06	1.67	72
6	2.5	1	1	3.09	263	0	3.19	4.19	1.67	59
7	1.8	0	1.5	2.11	320	0	2.31	7.75	1.67	76
8	2.0	0	1.5	2.77	311	.043	2.55	7.75	1.67	78
9	2.5	0	1.5	3.48	287	0	2.38	5.57	1.67	62
10	1.8	1	1.5	2.23	351	.149	2.55	7.59	1.67	78
11	2.0	1	1.5	3.08	337	1.05	2.70	7.60	1.67	85
12	2.5	1	1.5	4.40	302	.292	2.55	7.87	1.67	80
13	1.8	0	2	2.45	368	1.05	2.55	7.75	1.67	85
14	2.0	0	2	3.09	354	1.05	2.55	7.75	1.67	85
15	2.5	0	2	5.16	312	2.22	3.43	6.99	1.67	93
16	1.8	1	2	2.44	406	1.05	2.55	7.75	1.67	85
17	2.0	1	2	3.29	384	1.70	2.55	7.75	1.67	89
18	2.5	1	2	5.51	334	2.36	3.33	7.09	1.67	94

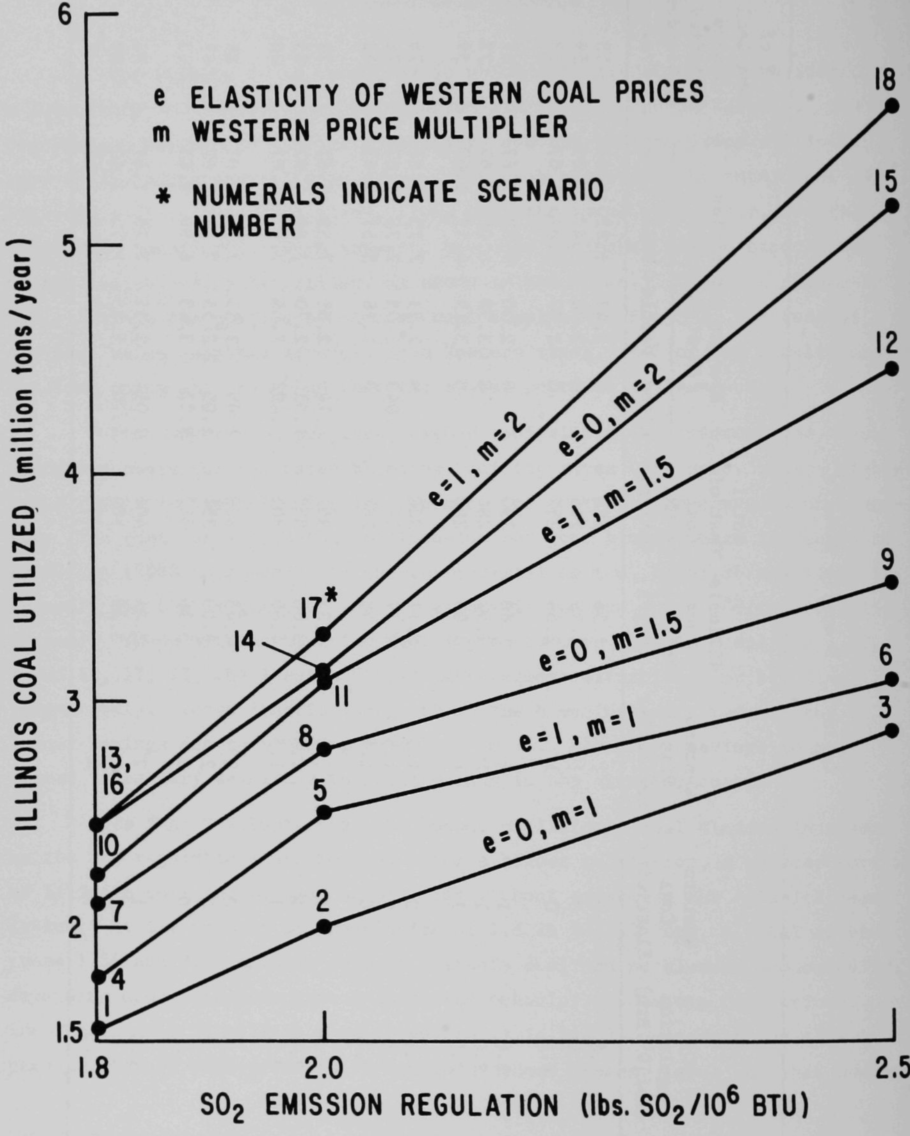

Fig. 9. Tons of Illinois Coal Used vs. SO_2 Emission Regulations

coal production can be expanded without increasing mine-mouth costs. As these are conservative assumptions, they indicate the baseline feasibility of coal blending. The figure of 2.45 million tons (Scenario 16) is based on extreme assumptions regarding the behavior of Western coal prices, hypothesizing that mine-mouth costs have doubled (multiplier = 2) and that they increase further as greater quantities are mined (elasticity = 1). The range of 1.56 to 2.45 million tons represents the quantities of Illinois coal that it would be economically feasible to blend at the 1.8 SO_2 regulation.

For an SO_2 regulation of 2.0 $lb/10^6$ Btu, the quantities of Illinois coal that could be blended economically lie in the range of 1.99 to 3.29 million tons/year. At the SO_2 regulation of 2.5 $lb/10^6$ Btu, the range is 2.86 to 5.51 million tons/year. Not only does the amount of Illinois coal that could be economically blended increase as the SO_2 regulations relax, but the range of tonnages increases, depending on the Western price assumptions.

The resulting MMA coal expenditures obtained in each scenario are presented in Fig. 10. At the present 1.8 SO_2 regulation, the lowest coal expenditures of $268 million per year are obtained (Scenario 1) using the most conservative assumptions about Western coal prices (elasticity = 0, multiplier = 1). If Western mine-mouth costs were to double and unit production costs to increase further with greater production (multiplier = 2, elasticity = 1), MMA coal expenditures would increase to $406 million per year (Scenario 16), even if coal blending was initiated to offset this effect. In all cases as the SO_2 regulations are relaxed, the total coal expenditures decrease because greater amounts of Illinois coal can be substituted for more expensive Western coal.

As Table 5 illustrates, it would be economically feasible to satisfy up to 58% of the MMA coal demand with blended coal at present SO_2 regulations and conservative assumptions about the behavior of Western coal prices (Scenario 1). As the price of Western coal increases relative to the price of Illinois coal (that is, as the Western price multiplier increases), the portion of coal demand satisfied by blended coal also increases, as would be expected. If Western coal prices were to double (Scenarios 13 through 18), it would be economically feasible to supply between 85 and 94% of the market demand with blended coal, *ceteris paribus*.

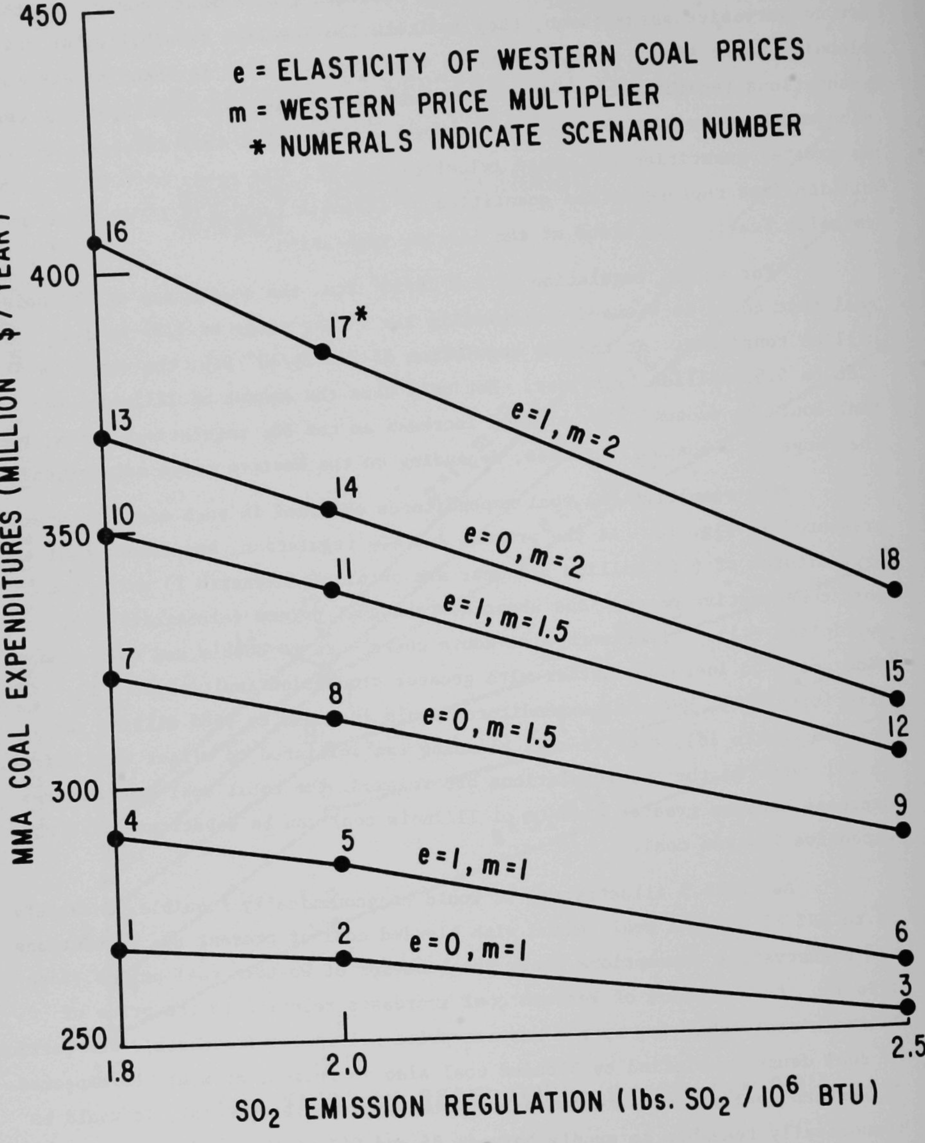

Fig. 10. Coal Expenditures with Blending vs. SO_2 Emission Regulations

The feasible blending facility capacities are also shown in Table 5. The feasibility of the Alton blender is particularly sensitive to Western coal prices. For conservative assumptions of Western coal price behavior (Scenarios 1 through 9), the Alton capacity is relatively insignificant. However, as the Western prices increase, its capacity stabilizes. This size variation is explained by the following argument. Alton is the closest blending site to the majority of Western coal mines. Coal from most of these mines can be shipped to Alton at a lower transportation cost than to the other blenders. For the conservative assumptions about the price of Western coal, some of the mines can supply a limited amount at prices less than that of blended coal. Since a least-cost objective has been assumed in this study, the cheaper Western coal is allocated to the Alton consumption region first. When the price of Western coal increases to a great enough degree (as in Scenarios 13 through 18), the blender becomes much less sensitive to it. Only if the price increased substantially would a stable market of more than one million tons/year exist for the Alton blender.

Stable markets appear to exist to support blenders in Peoria, Will, and Lake counties. Capacities range from 1.47 to 3.43 million tons/year for Peoria and from 3.67 to 7.87 million tons/year for Will County, with a constant of 1.67 million tons/year for Lake County. The Will County blender has a large range because it supplies much of the coal for the Cook demand region as well as its own demand region. Under all Western price assumptions and SO_2 regulations, the Lake blender captures the Lake market completely. Note also that since capacities of blenders were generally large, coal shipments to them could qualify for discounts on transportation charges.

Coal expenditures were calculated for the MMAs in which the coal blending was not an option -- all coal came directly from Western mines -- under both a conservative and an extreme estimate of Western coal price behavior. The results are presented in Table 6. For the conservative case (elasticity = 0; multiplier = 1) and the 1.8 SO_2 regulation, the MMA coal expenditures without blending amounted to \$280 million/year. On the other hand, coal expenditures amounted to \$268 million, a 4.1% savings, when blending was included. As the SO_2 regulation was relaxed, savings increased, up to 5.5% at the 2.5 regulation.

Table 6. Major Metropolitan Area Coal Expenditures With and Without Coal Blending

SO_2 Regulation ($lb/10^6$ Btu)	Western Coal Elasticity	Western Price Multiplier	Total MMA Coal Expenditures (10^6 \$/year)		Cost Savings due to Blending (10^6 \$/year)	% of Cost Saved by Introducing Blending
			Without Blending	With Blending		
1.8	0	1	279.8	268.3	11.5	4.1
2	0	1	279.8	265.6	14.2	5.1
2.5	0	1	266.1	251.5	14.6	5.5
1.8	1	2	466.5	406.2	60.3	12.9
2	1	2	466.5	384.1	82.4	17.6
2.5	1	2	421.5	333.6	87.9	20.8

At the extreme behavior of Western coal prices (elasticity = 1; multiplier = 2), coal blending predictably resulted in larger savings. At the 1.8 regulation, coal expenditures in the extreme case could be reduced by 12.9% with blending. For higher regulations, the savings increased up to 20.8% for an emission regulation of 2.5 lb $SO_2/10^6$ Btu. These savings are illustrated in Fig. 11.

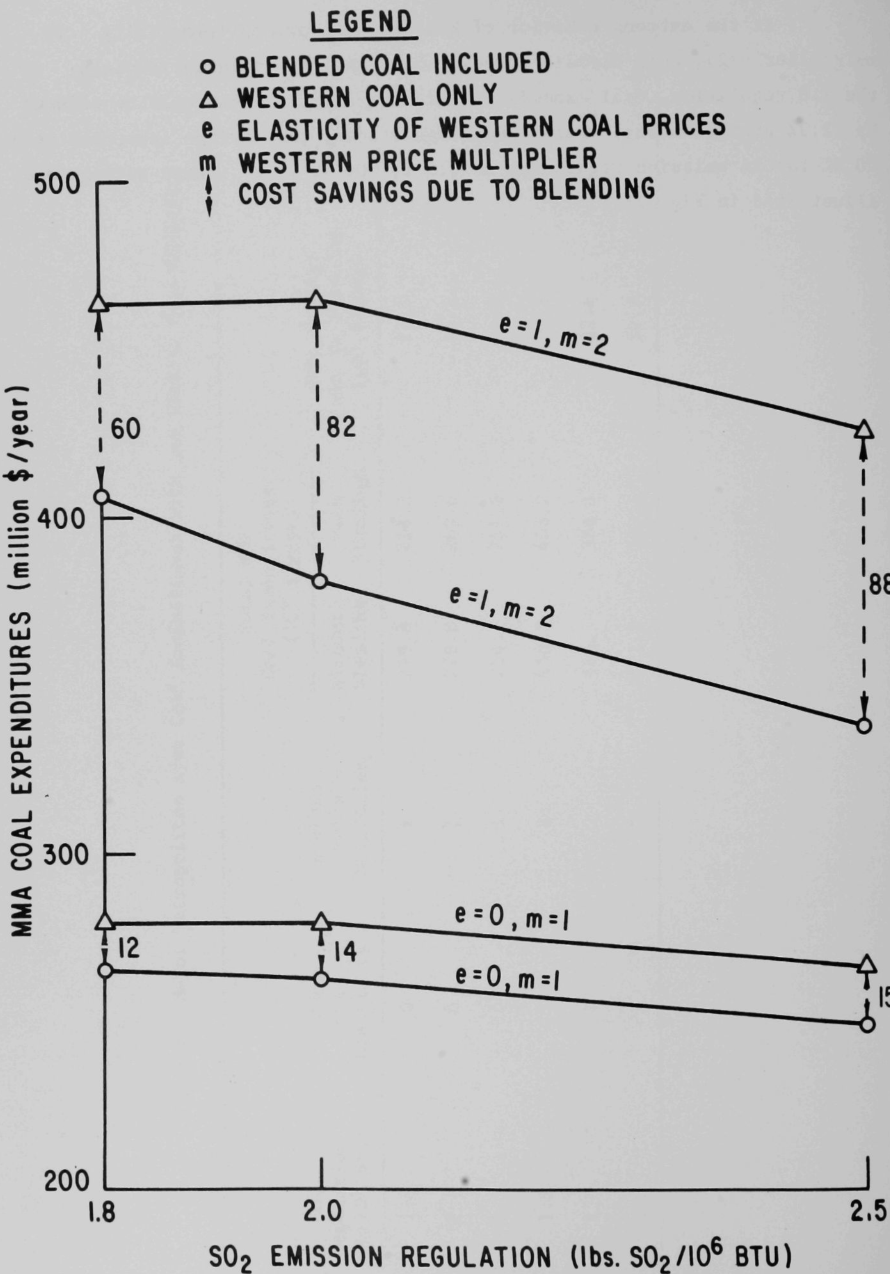

Fig. 11. Comparisons of MMA Coal Expendit
Blending vs. SO_2 Emission Regula

7. *CONCLUSIONS*

These economic feasibility studies revealed, under different SO_2 emission regulations and conservative assumptions about the future behavior of Western coal prices, that savings for Illinois in total expenditure for coal can be realized by utilizing coal blending. Among the findings are:

1. The cost savings to be realized by utilizing coal blending under present SO_2 regulations varies from 4% (using present Western) to 13% (for extreme Western prices).

2. The cost savings to be realized were much more dependent upon Western prices (relative to Illinois prices) than any variation of the SO_2 emission regulations.

3. Illinois coal utilization could be increased 1.5 to 2.5 million tons per year by utilizing coal blending under present SO_2 regulations.

4. As the regulations were relaxed, Illinois coal utilization increased by 1 to 3 million tons annually.

5. Since Illinois utilization increased as the regulations were relaxed, Illinois coal was being utilized in place of similarly priced Western coals.

6. Cost savings were not particularly sensitive to fluctuations in blending costs. When capitalization and annual operating costs increased 66% for 8 million tons per year and 164% for 4 million tons annual blending, the net reduction in savings was in the range of 2 to 3%.

All of the above conclusions were derived on the basis of the following assumptions.

Coal from each mine considered within the study is available. Each mine has the capacity to provide an amount of coal equal to one-third of its present production to the MMA demand points, which does not necessarily imply a one-third increase in production. The amount could be realized by shifting of present contracts, taking coal off the spot market and/or an increase in production, all totaling to an amount equal to one-third of the mine's present production.

The demand for coal within the MMA was assumed to be 80% of the 1970 consumption levels (less consumption of any boilers utilizing flue gas desulfurization systems). Even though not shown in the analysis of results sections, when different demand quantities were tested (full 1970 consumption, less scrubbers, and 50% of 1970 consumption), the amount of savings realized due to blending was very similar to the savings shown in Table 6. The benefits of coal blending do not appear to be particularly sensitive to demand fluctuations.

The sulfur and heating values determined from the data base were assumed to represent accurately the characteristics of the actual coal produced at each mine. These data base assumptions for obtaining the sulfur percentage and the heating value (Btu/lb) seem to be well substantiated, since the COAL WEEK figures for sulfur and Btu's match up well with values found in the *Keystone Coal Industry Manual* and other references.

The mine-mouth price used for the coal being produced at each mine was based only on contract prices (i.e., no spot prices were used) negotiated by utility companies at the highest mine-mouth price found in the data base. The highest mine-mouth price for each mine is deemed to represent the price most likely to be quoted should a coal blending facility or group initiate a contract with the mine in the near future.

It was assumed that the smaller users could form a regional co-op and thereby be able to negotiate contract prices to meet their demands. A comparison of satisfying the demand with coal blending and satisfying the same demand using strictly Western coals shows that if smaller users would buy Western coal on a co-op basis, a savings could be realized. However, if the same co-op utilized blended coal, a savings over buying strictly Western coal could also be realized. If coal blending can be shown to be economically feasible through the application of these conservative assumptions, any less conservative situations that arise will only enhance the economic feasibility of coal blending.

The major conclusion to be drawn from this study is that by locating a blending facility within a large demand region, coal blending offers coal users a means of purchasing a fuel that is cheaper than Western coal and of meeting the SO_2 emission regulations as well.

8. COAL BLENDING DEMONSTRATION FACILITY

This chapter examines the need to study the operational feasibility of coal blending by discussing the previous and present uses of blended coal and the operational problems encountered when burning low sulfur Western coal in boilers not specifically designed to burn it. This discussion is followed by recommendations for an operational demonstration project.

Coal blending has been shown to be economically feasible based on the following factors: current and projected prices of Illinois and Western coals, transportation costs (from mine to blending facility and in turn to users), and blending facility costs made up of annual operating and capitalization costs. These factors represent only the economic feasibility of coal blending and do not reflect any operational problems that might occur during the burning of blended coal.

8.1 OPERATIONAL ASPECTS

The blending process has been used previously to obtain coke, to maintain constant heating value (Btu/lb), and to extend supply during a shortage of regional coal. Blending of coal to obtain the desirable characteristics of metallurgical coke has been a standard practice for years. The blends are used to reduce the rough surfaces and to increase the coke uniformity. As these criteria are met, a better metallurgical coke results and blast furnace performance improves. At Utah International's Navajo mine, coal from different seams is being blended to maintain a desired heating value range of 8900 Btu/lb. Coal brought to the blending facility is analyzed for Btu content; a computer then directs the stacker to which of ten elongate piles to place the coal to achieve the desired Btu blend. Reclaimers pick up the coal, mix it, and feed it into the boilers at the Four Corners power plant near Fruitland, New Mexico. A similar operation services the French National Coal Board's 750-ton-per-hour Lucy power plant located near Montceau les Mines, France. The plant operation contains 75,000-ton piles of layered coal. As the reclaimer picks up the coal from the pile, its movements help to mix the different layers so that the specified Btu range is achieved.

Additionally, coal blending is helping to overcome problems that arise when low sulfur coal is burned in a unit designed for high sulfur coal, because most boilers are designed to burn a specific type of coal. Slagging, fouling, carbon carryover, and other combustion problems seem to be most prominent. The combustion problems can be partially eliminated by adding a combustion "sweetener," such as torch oil or blending coke, or some type of coal that the unit was designed to burn. Sweeteners enhance the combustion characteristics of the fuel and generally regain some of the efficiency lost when burning only low sulfur coal. Several plants are using sweeteners to produce a blend of two coals having characteristics approximating the coal that the boiler was originally designed to burn.

8.2 OPERATIONAL DEMONSTRATION PROJECT

Empirical data necessary to substantiate the linear combining relationship of the high- and low-sulfur coals to be blended should be provided by an operational demonstration project. At this time, sufficient knowledge does not exist concerning the operational problems and detailed operational cost data associated with the blending of coal; nor has comprehensive stack emission data been gathered to determine the effect on SO_2 emissions of using blended coal. No commercial facility or experimental installation now exists that is gathering and analyzing this much needed data. It is therefore proposed that such a facility be set up at an appropriate site to conduct the necessary experimental work.

Three main considerations have been identified as being necessary in selecting the facility:

1. The general configuration of the boiler and its feed system, along with size, should be representative of the most commonly used equipment.

2. The boiler must be continuously available for approximately six months, during which time it is to be regulated to accommodate the experimental work.

3. The site must be serviced by both rail and truck for coal delivery. In addition, there must be sufficient ground area to permit the stockpiling of several different coals simultaneously.

A step-by-step description of the operation to be performed by a coal blending facility follows.

The coal to be tested is to be received by either rail or truck and stockpiled in the storage area (refer to Fig. 12) for sampling and analyzing prior to blending. Each type of coal is then loaded onto a portable conveyor where it is to be weighed and put into the crusher. A simultaneous feeding into the crusher of both coals coupled with its mixing action facilitates the blending. The equipment is to include an accurate coal measuring and checking system to ensure the maintenance at all times of the proper proportions of high- and low-sulfur coals. A pair of variable speed conveyor belts, with the ratio of speeds set at the f_L/f_H ratio, keeps the coal amounts in proper proportion. Before and after blending, all coals are to be analyzed for the following characteristics: heating value (Btu/lb) and percentages of moisture, volatile matter, fixed carbon, ash, and sulfur. The blended coal is then transported to the top of the storage hopper from which it is fed into the boiler.

Analyses and evaluations of the various effects produced in operating the blending facility are scheduled:

1. Compressive stack gas monitoring equipment and related systems are to be installed to determine the amounts of SO_2 and particulate matter that are present in the stack gas.

2. Alternative procedures are to be investigated to determine what effects they have on combustion, emissions, and ash generation.

3. Stack gas temperatures and velocities are to be monitored and their effects on the dispersion patterns are to be evaluated.

4. The effects of fuel mix on precipitator efficiency and the effectiveness of stack gas conditioning are to be evaluated.

5. All waste products are to be collected and analyzed to determine what effects blending has on their mechanical and physical properties.

With these procedures ongoing, a mass balance of the sulfur should be obtained. From this mass balance a determination can be made as to how much of the sulfur is retained in the ash and how much actually is emitted through the stack.

Additionally, meteorological data are to be collected and used to correlate with the sulfur emissions data and sulfur content of the blended

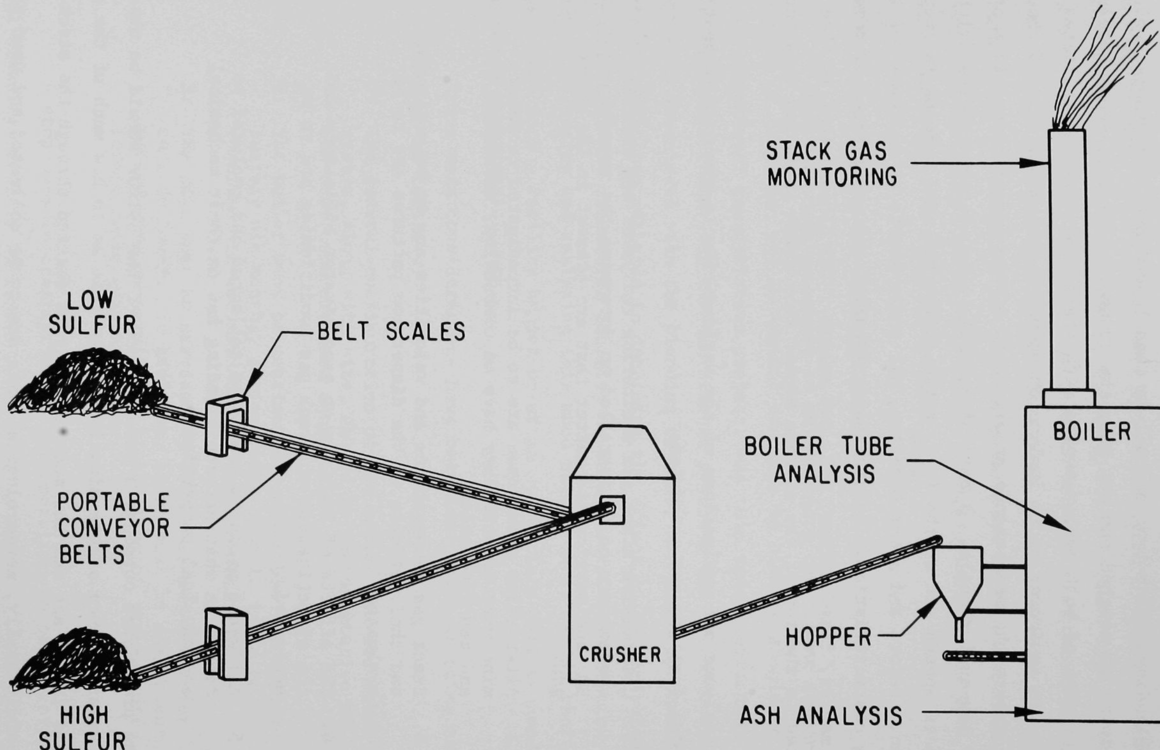

Fig. 12. Coal Blending Demonstration Facility

coal. Several possible blends are to be used so that the effects of each on plant efficiencies and operations can be studied.

The operation of the demonstration project is to include assessment of results following periodic tests and assessment of final strategy regarding the continued and acceptable use of Illinois coal. After each test period, the boiler is to be shut down, the boiler tubes are to be inspected, and any slagging or fouling problems are to be noted. After all the selected blends have been tested, all the data would then be collected and analyzed to assess the best possible strategy for the continued use of Illinois coal while simultaneously maintaining the sulfur emission regulations.

9. RECOMMENDATIONS

For the implementation of coal blending to be advantageous, the operational aspects of combining high- and low-sulfur coals in developing a new fuel must be examined. It is recommended that a comprehensive operational coal blending demonstration facility be initiated to provide tested information on how the characteristics of the separate coals would interrelate and unite in the blend. By sampling stack gases, the amount of sulfur emitted from particular blends could be established. Additional costs that would be incurred due to ash handling or combustion problems also could be identified. The described demonstration project would serve to determine the operational feasibility and to identify the factors involved in the economic feasibility of blending high- and low-sulfur coals.

APPENDIX A. COAL BLENDING METHODOLOGY

For this study, we have assumed that the different coals used in the blends combine in a linear relationship. This assumption must be made since empirical data is unavailable to prove or disprove it. The U.S. Environmental Protection Agency publication "Compilation of Air Pollutant Emission Factors," gives an emission factor of 38 lb/ton times percent sulfur for bituminous coal burned in external combustion sources without pollution control equipment. This factor gives emissions on a "pounds of SO_2 per ton of coal burned" basis.

$$\text{Emissions in } \frac{\text{lb } SO_2}{\text{ton}} = 38S, \tag{1}$$

where

S = the percent sulfur contained in the coal.

To convert this expression to a "lb $SO_2/10^6$ Btu" basis, the norm in which the Illinois SO_2 regulations have been established (see Fig. 1), the divisor is multiplied by 2000 lb/ton of coal (Eq. 2) and by Btu/lb (Eq. 3) and both numerator and denominator multiplied by 10^6 (Eq. 4) to arrive at Eq. 5, as follows:

$$\text{Emissions in } \frac{\text{lb } SO_2}{\text{lb}} = \frac{\text{lb } SO_2}{\text{ton}} \frac{\text{ton}}{2000 \text{ lb}} = \frac{38S}{2000}, \tag{2}$$

and

$$\text{Emissions in } \frac{\text{lb } SO_2}{\text{Btu}} = \frac{38S \text{ lb } SO_2}{2000 \text{ lb}} \frac{\text{lb}}{\text{H (Btu)}} = \frac{38S}{\text{H } (2000)}, \tag{3}$$

where

1 lb of coal contains "H" Btu

or coal has heating value of H (Btu/lb);

and

$$\text{Emissions in } \frac{\text{lb } SO_2}{10^6 \text{ Btu}} = \frac{38S}{\text{H } (2000)} \times 10^6 = \frac{19000 \text{ (S)}}{\text{(H)}}. \tag{4}$$

In the Illinois MMAs, the SO_2 emission regulation is 1.8 lb $SO_2/10^6$ Btu. Eq. 4 now becomes:

$$\text{Emissions} = 1.8 \frac{\text{lb } SO_2}{10^6 \text{ Btu}} = \frac{19000 \text{ (S)}}{\text{(H)}}. \tag{5}$$

In a state like Illinois where the regulation for major metropolitan areas call for SO_2 emissions less than or equal to 1.8 lb $SO_2/10^6$ Btu of coal burned, the corresponding equation would be:

$$\frac{1.8 \text{ lb } SO_2}{10^6 \text{ Btu}} \geq \frac{19000 \text{ (S)}}{\text{(H)}} . \tag{6}$$

If we are to burn two types of coals (high- and low-sulfur), the fraction of each type of coal in the blend must equal unity.

$$f'_H + f'_L = 1,$$

or (7)

$$f'_H = 1 - f'_L,$$

where

f'_L = fraction of low sulfur coal (heat input basis);
f'_H = fraction of high sulfur coal (heat input basis).

The emissions of such a blend would have to meet the lb of $SO_2/10^6$ regulations. Equation 8 would yield the SO_2 emission of this blend.

$$\frac{E \text{ lb } SO_2}{10^6} = \left(\frac{19000\ S_H}{H_H}\right) f'_H + \left(\frac{19000\ S_L}{H_L}\right) f'_L , \tag{8}$$

where

S_H = % sulfur of high sulfur coal,
S_L = % sulfur of low sulfur coal,
H_H = Btu/lb of high sulfur coal,
H_L = Btu/lb of low sulfur coal, and
E = emission regulation in lb $SO_2/10^6$ Btu.

Substituting Eq. 7 into Eq. 8 enables one to solve for the low sulfur fraction of the blend, as follows:

$$E = \left(\frac{19000\ S_H}{H_H}\right)\left(1 - f'_L\right) + \left(\frac{19000\ S_L}{H_L}\right) f'_L ; \tag{9}$$

and

$$E = \frac{19000\ S_H}{H_H} - \left(\frac{19000\ S_H}{H_H}\right) f'_L + \left(\frac{19000\ S_L}{H_L}\right) f'_L . \tag{10}$$

Dividing both sides of Eq. 10 by 19000 yields:

$$\frac{E}{19000} = \frac{S_H}{H_H} - \left(\frac{S_H}{H_H}\right) f'_L + \left(\frac{S_L}{H_L}\right) f'_L \; . \tag{11}$$

Adding $\frac{S_H}{H_H} f'_L$ to each side of Eq. 11 yields:

$$\frac{E}{19000} + \left(\frac{S_H}{H_H}\right) f'_L = \frac{S_H}{H_H} + \left(\frac{S_L}{H_L}\right) f'_L \; . \tag{12}$$

Subtracting $\left(\frac{S_L}{H_L}\right) f'_L$ and $\frac{E}{19000}$ from each side of Eq. 12 yields:

$$\frac{S_H}{H_H} \left(f'_L\right) - \left(\frac{S_L}{H_L}\right) f'_L = \frac{S_H}{H_H} - \frac{E}{19000} \; . \tag{13}$$

Regrouping the left-hand side of Eq. 13 yields:

$$f'_L \left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right) = \left(\frac{S_H}{H_H} - \frac{E}{19000}\right) \; . \tag{14}$$

Dividing both sides of Eq. 14 by $\left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right)$ yields:

$$f'_L = \frac{\left(\frac{S_H}{H_H} - \frac{E}{19000}\right)}{\left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right)} \; , \tag{15}$$

and, similarly

$$f'_H = \frac{\left(\frac{S_L}{H_L} - \frac{E}{19000}\right)}{\left(\frac{S_L}{H_L} - \frac{S_H}{H_H}\right)} \; . \tag{16}$$

In this case, f_L' and f_H' are in terms of the total Btu produced by the blend. Since both Btu's and sulfur are given in terms of weight, the real f_H and f_L that are desired are the fractions by weight of the blended coal.

$$f_H = W_H/(W_L + W_H) \tag{17}$$

and

$$f_L = W_L/(W_L + W_H) \ , \tag{18}$$

where

W_L = weight of low sulfur coal,
W_H = weight of high sulfur coal,
$W_L + W_H$ = total weight,
f_H = fraction of high sulfur coal on a weight basis, and
f_L = fraction of low sulfur coal on a weight basis.

Since f_L' and f_H' are the fraction of each respective coal's Btu's present in the blend:

$$W_L \ H_L = f_L' \text{ or } W_L = \frac{f_L'}{H_L} \tag{19}$$

and

$$W_H \ H_H = f_H' \text{ or } W_H = \frac{f_W'}{H_H} \tag{20}$$

The result of substituting Eq. 18 and 19 into Eq. 17 is:

$$f_L = \frac{f_L'}{H_L} \Bigg/ \left(\frac{f_L'}{H_L} + \frac{f_H'}{H_H}\right) . \tag{21}$$

The result of substituting Eq. 15 and 16 into Eq. 20 is:

$$f_L = \frac{\left(\frac{S_H}{H_H} - \frac{E}{19000}\right)}{H_L \left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right)} \Bigg/ \left(\frac{\left(\frac{S_H}{H_H} - \frac{E}{19000}\right)}{H_L \left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right)} + \frac{\left(\frac{S_L}{H_L} - \frac{E}{19000}\right)}{H_H \left(\frac{S_L}{H_L} - \frac{S_H}{H_H}\right)} \right) . \tag{22}$$

Multiplying both sides of Eq. 22 by:

$$\left(\frac{\frac{S_H}{H_H} - \frac{E}{19000}}{H_L \left(\frac{S_H}{H_H} - \frac{S_L}{H_L} \right)} + \frac{\frac{S_L}{H_L} - \frac{E}{19000}}{H_H \left(\frac{S_L}{H_L} - \frac{S_H}{H_H} \right)} \right) \text{ yields:}$$

$$\left(\frac{f_L}{H_L} \right) \frac{\left(\frac{S_H}{H_H} - \frac{E}{19000} \right)}{\left(\frac{S_H}{H_H} - \frac{S_L}{H_L} \right)} + \left(\frac{f_L}{H_H} \right) \left(\frac{\frac{S_L}{H_L} - \frac{E}{19000}}{\frac{S_L}{H_L} - \frac{S_H}{H_H}} \right) = \frac{\left(\frac{S_H}{H_H} - \frac{E}{19000} \right)}{H_L \left(\frac{S_H}{H_H} - \frac{S_L}{H_L} \right)} \qquad (23)$$

Multiplying both sides of Eq. 23 by $H_L \left(\frac{S_H}{H_H} - \frac{S_L}{H_L} \right)$ yields:

$$f_L \left(\frac{S_H}{H_H} - \frac{E}{19000} \right) + \left(\frac{f_L}{H_H} \right) \left(\frac{\frac{S_L}{H_L} - \frac{E}{19000}}{\frac{S_L}{H_L} - \frac{S_H}{H_H}} \right) H_L \left(\frac{S_H}{H_H} - \frac{S_L}{H_L} \right) \qquad (24)$$

$$= \left(\frac{S_H}{H_H} - \frac{E}{19000} \right) .$$

Dividing both sides of Eq. 24 by $\left(\frac{S_H}{H_H} - \frac{E}{19000} \right)$ yields:

$$f_L + f_L \frac{\left(\left(\frac{S_L}{H_L} \right) - \left(\frac{E}{19000} \right) \right)}{\left(\frac{S_L}{H_L} - \frac{S_H}{H_H} \right)} \frac{H_L}{H_H} \frac{\left(\frac{S_H}{H_H} - \frac{S_L}{H_L} \right)}{\left(\frac{S_H}{H_H} - \frac{E}{19000} \right)} = 1 \qquad (25)$$

Subtracting f_L from both sides of Eq. 25 yields:

$$f_L \frac{\left(\frac{S_L}{H_L} - \frac{E}{19000}\right)}{\left(\frac{S_L}{H_L} - \frac{S_H}{H_H}\right)} \frac{H_L}{H_H} \frac{\left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right)}{\left(\frac{S_H}{H_H} - \frac{E}{19000}\right)} = 1 - f_L \tag{26}$$

As in Eq. 6:

$$f_L + f_H = 1 \text{ or } f_H = 1 - f_L \tag{27}$$

By substituting Eq. 27 into Eq. 26 and multiplying both sides of Eq. 26 by:

$$\left(\frac{S_L}{H_L} - \frac{S_H}{H_H}\right)\left(\frac{S_H}{H_H} - \frac{E}{19000}\right) \quad \text{yields:}$$

$$f_L H_L \left(\frac{S_L}{H_L} - \frac{E}{19000}\right)\left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right) - f_H H_H \left(\frac{S_L}{H_L} - \frac{S_L}{H_H}\right)\left(\frac{S_H}{H_H} - \frac{E}{19000}\right) \tag{28}$$

Regrouping both sides of Eq. 28 yields:

$$f_L \left(S_L - \frac{E\ H_L}{19000}\right)\left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right) = f_H \left(S_H - \frac{E\ H_H}{19000}\right)\left(\frac{S_L}{H_L} - \frac{S_H}{H_H}\right) \tag{29}$$

Dividing both sides of Eq. 29 by $\left(\frac{S_L}{H_L} - \frac{S_H}{H_H}\right)$ yields:

$$f_L \left(S_L - \frac{E\ H_L}{19000}\right) \frac{\left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right)}{\left(\frac{S_L}{H_L} - \frac{S_H}{H_H}\right)} = f_H \left(S_H - \frac{E\ H_H}{19000}\right) \tag{30}$$

Recognizing that

$$\left(\frac{S_H}{H_H} - \frac{S_L}{H_L}\right) \Bigg/ \left(\frac{S_L}{H_L} - \frac{S_H}{H_H}\right) = -1,$$

and substituting this into Eq. 30 yields:

$$f_L \left(S_L - \frac{E\ H_L}{19000}\right) (-1) = f_H \left(S_H - \frac{E\ H_H}{19000}\right). \tag{31}$$

Adding $f_L \left(S_L - \frac{E\ H_L}{19000}\right)$ to both sides of Eq. 31 yields:

$$f_H \left(S_H - \frac{E\ H_H}{19000}\right) + f_L \left(S_L - \frac{E\ H_L}{19000}\right) = 0\ . \tag{32}$$

For illustrative purposes, let us try an example problem. Let S_L = 0.50%, S_H = 3.00%, H_H = 10,000 Btu/lb, H_L = 9,000 Btu/lb, E = 1.8 lb $SO_2/10^6$ Btu. By substituting these values into Eq. 31, the equation becomes:

$$f_H \left(3.0 - \frac{1.8\ (10000)}{19000}\right) + (1 - f_H) \left(0.50 - \frac{1.8\ (9000)}{19000}\right) = 0$$

$$f_H\ (3.0 - 0.947) + (1 - f_H)\ (0.50 - .852) = 0$$

$$2.052\ (f_H) - 0.352 + .352\ f_H = 0$$

$$2.405\ f_H = 0.352$$

$$f_H = \frac{0.352}{2.405} = .1466, \text{ i.e., } 14.66\%.$$

This means 14.66% of this high sulfur coal and 85.34% of this low sulfur coal (both by weight) could be blended to meet a 1.8 lb $SO_2/10^6$ Btu regulation. To check these figures, assume a total weight of 10000 lb.

$$10000 \text{ lb} \times f_H = 1466 \text{ lb of high sulfur coal}$$

$$1000 \text{ lb} \times f_L = 8534 \text{ lb of low sulfur coal}$$

$$1466 \text{ lb} \; \frac{10000 \text{ Btu}}{\text{lb}} = 14.66 \times 10^6 \text{ Btu produced by high sulfur coal}$$

$$8534 \text{ lb} \; \frac{9000 \text{ Btu}}{\text{lb}} = \frac{76.80 \times 10^6 \text{ Btu produced by low sulfur coal}}{91.46 \times 10^6 \text{ Btu produced by blend}}$$

1000 lb of this blend produces 91.46×10^6 Btu. The high sulfur fraction of the blend based on Btu content is:

$$\frac{14.66 \times 10^6 \text{ Btu}}{91.46 \times 10^6 \text{ Btu}} = f'_H = .1603, \text{ i.e., } 16.03\%.$$

Eq. 16 gives the high sulfur fraction of any blend based on Btu content by substituting the example problem values into (16) the result is:

$$f'_H = \frac{\frac{0.50}{9000} - \frac{1.8}{19000}}{\frac{0.50}{9000} - \frac{3.0}{10000}} = \frac{-3.918 \times 10^{-5}}{-2.444 \times 10^{-4}} = .1603.$$

The results of the example problem show that the fraction of either type of coal can be calculated either on a Btu basis (f'_H and f'_L, Eq. 16) or a weight basis (f_H and f_L, Eq. 31).

APPENDIX B. COAL MINE DATA FOR ILLINOIS AND WESTERN STATES

Table B.1. Coal Mine Data: Illinois

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Peabody Coal Co.	#10 (D)	6	Christian (Pawnee)	12-14	16.9	4.2	9,300	91.5CE	Hammond, IN	CE	K-CW24	4,131,900	4,147,069
					16.3	4.5	9,600	95.6S	Coffeen, IL	CIPSC	CW24		
					16.9	4.2	9,300	80.3CE	Joliet, IL	CE	CW24		
					16.9	4.2	9,300	85.7CE	Kincaid, IL	CE	CW24		
							9,900	108.0C	Springfield, IL	SWLPD	CW13		
							10,000	108.0C	Springfield, IL	SWLPD	CW6		
							9,600	82.9CE	Dixon, IL	CE	CW3		
							8,700	92.0CE	Joliet, IL	CE	CW3		
					14.1	4.3	10,000	108.4C	Springfield, IL	SWLPD	CW28		
					14.1	4.3	10,000	108.4C	Springfield, IL	SWLPD	CW28		
							10,000	108.4C	Springfield, IL	SWLPD	CW23		
							10,000	108.4C	Springfield, IL	SWLPD	CW23		
							9,300	71.9CE	Hammond, IN	CE	CW21		
							9,300	77.9CE	Joliet, IL	CE	CW18		
							9,300	83.2CE	Waukegan, IL	CE	CW18		
							9,300	57.7CE	Kincaid, IL	CE	CW18		
							10,000	108.0C	Springfield, IL	SWLPD	CW18		
							9,400	69.5CE	Hammond, IN	CE	CW14		
							9,400	85.5CE	Dixon, IL	CE	CW14		
							9,400	49.2CE	Kincaid, IL	CE	CW14		
							9,400	74.5CE	Waukegan, IL	CE	CW14		
							10,000	108.0C	Springfield, IL	SWLPD	CW12		
							10,000	108.0C	Springfield, IL	SWLPD	CW12		
							9,400	63.9CE	Hammond, IN	CE	CW10		
							9,400	76.1CE	Joliet, IL	CE	CW10		
							9,400	72.6CE	Waukegan, IL	CE	CW10		
							9,400	49.5CE	Kincaid, IL	CE	CW10		
							9,400	80.6CE	Dixon, IL	CE	CW10		
					16.6	4.1	9,400	40.8CE	Kincaid, IL	CE	CW30		
					16.6	4.1	9,400	78.5CE	Dixon, IL	CE	CW30		
					16.6	4.1	9,400	69.2CE	Hammond, IN	CE	CW30		
					16.6	4.1	9,400	74.5CE	Joliet, IL	CE	CW30		
					16.3	4.5	9,600	95.6S	Coffeen, IL	CIPSC	CW32		
					14.1	4.3	10,000	111.1C	Springfield, IL	SWLPD	CW34		
					14.1	4.3	10,000	111.1C	Springfield, IL	SWLPD	CW34		
							9,400	75.4CE	Joliet, IL	CE	CW14		
							9,900	108.0C	Springfield, IL	SWLPD	CW3		

Illinois (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Peabody Coal Co.	River King (S)(D)	6	St. Clair (Freeburg)	10-13	10.1	3.4	12,100	136.2CE	Meredosia, IL	CIPSC	K-CW 24	6,474,187	4,296,663(S)
					11.4	3.2	10,300	60.3CE	Dune Acres, IN	NIPSCO	CW24		2,229,604(D)
							10,600	45.1C	Memphis, TN	TVA	CW1		
							10,400	139.5CE	Meredosia, IL	CIPSC	CW3		
							10,400	55.5CE	Dune Acres, IN	NIPSCO	CW1		
							10,500	38.6CE	Memphis, TN	TVA	CW9		
							10,600	58.8CE	Michigan City, IN	NIPSCO	CW9		
							10,700	83.3CE	Clinton, IA	IPC	CW23		
							10,500	84.4CE	Dubuque, IA	IPC	CW23		
							9,600	54.4CE	Marston, MO	AEC	CW21		
							10,700	87.4CE	Cassville, WI	WSPLC	CW21		
							10,400	90.5CE	Genoa, WI	DPC	CW21		
							10,600	88.7CE	Alma, WI	DPC	CW21		
							10,700	87.8CE	Alma, WI	DPC	CW21		
							10,900	82.6CE	Clinton, IA	IPC	CW18		
							10,700	82.2CE	Dubuque, IA	IPC	CW18		
							9,600	53.9CE	Marston, MO	AEC	CW13		
							10,600	87.7CE	Genoa, WI	DPC	CW13		
							11,000	115.2S	Springfield, IL	SWLPD	CW12		
							10,400	136.1CE	Meredosia, IL	CIPSC	CW11		
							10,900	74.4CE	Clinton, IA	IPC	CW11		
							9,800	54.1CE	Marston, MO	AEC	CW10		
					11.3	3.2	10,400	91.6CE	Alma, WI	DPC	CW30		
					12.3	3.1	10,700	89.3CE	Genoa, WI	DPC	CW30		
					10.1	3.4	12,100	137.1CE	Meredosia, IL	CIPSC	CW32		
					12.0	3.3	10,600	91.0CE	Genoa, WI	DPC	CW34		
					12.1	4.1	10,600	90.4CE	Alma, WI	DPC	CW34		
					12.1	3.3	10,800	88.7CE	Alma, WI	DPC	CW34		
							11,000	115.2S	Springfield, IL	SWLPD	CW13		
							10,700	82.5CE	Clinton, IA	IPC	CW13		
							11,000	88.5C	Dubuque, IA	IPC	CW13		
Consolidation Coal Co.	Norris(S)	5	Fulton (Norris)	14-18			10,400	82.1C	Bartonville, IL	CILC	K-CW8	794,715	1,049,750
							10,400	72.5C	Bartonville, IL	CILC	CW3		
							10,200	83.2C	Bartonville, IL	CILC	CW6		
							10,700	81.6C	East Peoria, IL	CILC	CW8		
							10,200	92.5C	Bartonville, IL	CILC	CW23		
							10,100	86.7C	East Peoria, IL	CILC	CW21		
							10,300	83.0C	Bartonville, IL	CILC	CW21		
							10,200	83.5C	Bartonville, IL	CILC	CW14		
							10,400	85.1C	East Peoria, IL	CILC	CW14		
							10,700	81.6C	East Peoria, IL	CILC	CW10		
							10,400	82.1C	Bartonville, IL	CILC	CW10		
					9.7	2.4	10,400	94.1C	Bartonville, IL	CILC	CW30		
					10.4	2.4	10,100	96.9C	Bartonville, IL	CILC	CW34		

Illinois (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Old Ben Coal Co.	#24(D)	6	Franklin (Benton)	7-10	11.6	2.7	11,200	40.9CE	St. Charles, MD	UEC	K-CW24	1,959,834	2,377,482
							10,300	52.5C	Paducah, KY	TVA	CW1		
							10,300	86.6NC	Paducah, KY	TVA	CW1		
							10,400	85.8C	Paducah, KY	TVA	CW9		
					19.5	2.9	10,200	80.5CE	Paducah, KY	TVA	CW27		
							10,400	86.2C	Paducah, KY	TVA	CW20		
							11,100	40.8CE	St. Charles, MO	UEC	CW20		
							11,100	41.4CE	St. Charles, MO	UEC	CW20		
							11,100	41.7CE	St. Charles, MO	UEC	CW20		
							10,400	86.6CE	Paducah, KY	TVA	CW17		
							11,100	41.2CE	St. Charles, MO	UEC	CW17		
							11,200	40.1CE	St. Charles, MO	UEC	CW12		
					19.5	2.9	10,200	86.7C	Paducah, KY	TVA	CW32		
					11.0	2.7	11,200	40.9CE	West Alton, MO	UEC	CW32		
					11.0	2.7	11,200	41.5CE	West Alton, MO	UEC	CW32		
Old Ben Coal Co.	#26 (D)	6	Franklin (Sesser)	7-10			10,900	122.4S	Joppa, IL	EEI	K-CW3	1,738,593	2,100,316
					17.3	2.4	10,500	83.3C	Paducah, KY	TVA	CW27		
							10,700	81.5C	Paducah, KY	TVA	CW20		
							10,700	82.1CE	Paducah, KY	TVA	CW17		
							10,700	82.2C	Paducah, KY	TVA	CW9		
					17.3	2.4	10,500	81.4C	Paducah, KY	TVA	CW32		
							10,700	80.9NC	Paducah, KY	TVA	CW1		
Peabody Coal Co.	Eagle #2(D)	5	Gallatin (Shawneetown)	5-7	10.6	2.7	11,800	87.7C	Lynn Haven, FL	GPC	K-CW24	1,371,444	1,021,522
							11,600	78.1C	Bucks, AL	ALPC	CW3		
							11,700	87.0C	Pensacola, FL	GPC	CW6		
							11,600	88.8C	Lynn Haven, FL	GPC	CW3		
							11,700	87.0C	Pensacola, FL	GPC	CW3		
							11,800	112.7C	St. Louis, MO	UEC	CW20		
							12,000	84.5C	Bucks, AL	ALPC	CW14		
							11,800	113.0C	St. Louis, MO	UEC	CW12		
							11,900	70.2C	Gulfport, MS	MSPC	CW11		
							11,500	76.3C	Gulfport, MS	MSPC	CW11		
							11,700	86.4CE	Bucks, AL	ALPC	CW10		
							11,800	88.3C	Lynn Haven, FL	GPC	CW10		
					11.6	3.0	11,800	86.4C	Pensacola, FL	GPC	CW30		
					10.7	2.7	11,800	73.9C	Gulfport, MS	MSPC	CW30		
					10.1	2.9	11,400	84.4C	Gulfport, MS	MSPC	CW30		
					11.2	2.7	11,800	87.7C	Lynn Haven, FL	GPC	CW30		
					10.5	2.9	11,800	105.8C	Bucks, AL	ALPC	CW34		
					10.6	2.9	11,800	86.6C	Pensacola, FL	GPC	CW34		

Illinois (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Consolidation Coal Co.	Burning Star #4(S)	5 & 6	Perry (Cutler)	8-13			10,800	78.9S	East Peoria, IL	CILC	K-CW6	1,651,789	745,196
							11,100	78.9S	Bartonville, IL	CILC	CW8		
							11,200	44.2CE	Labadie, MO	UEC	CW20		
							11,200	48.9CE	St. Charles, MO	UEC	CW17		
							11,200	44.4CE	Labadie, MO	UEC	CW17		
					10.1	3.1	11,200	48.8CE	Labadie, MO	UEC	CW32		
Consolidation Coal Co.	Hillsboro(D)	6	Montgomery (Coffeen)	12-14	18.9	3.9	9,300	53.0CE	Coffeen, IL	CIPSC	K-CW24	1,640,105	1,887,638
							9,300	42.5CE	Coffeen, IL	CIPSC	CW3		
							9,500	52.5CE	Coffeen, IL	CIPSC	CW21		
							9,300	42.6CE	Coffeen, IL	CIPSC	CW11		
					19.3	3.9	9,500	63.3CE	Coffeen, IL	CIPSC	CW32		
Consolidation Coal Co.	Burning Star #3(S)	5 & 6	Randolph (Sparta)	8-13	10.1	3.1	11,200	47.0CE	St. Louis, MO	UEC	K-CW24	1,233,954	1,387,282
							10,900	88.8CE	Clinton, IA	IPC	CW6		
							11,200	86.6C	Lansing, IA	IPC	CW23		
							11,100	90.3C	Clinton, IA	IPC	CW18		
							11,300	86.0C	Lansing, IA	IPC	CW18		
							11,100	88.3C	Dubuque, IA	IPC	CW18		
							11,200	47.0CE	St. Louis, MO	UEC	CW12		
							10,900	89.4C	Clinton, IA	IPC	CW11		
							11,000	88.6CE	Dubuque, IA	IPC	CW11		
							11,000	90.8C	Clinton, IA	IPC	CW13		
							11,100	87.5C	Lansing, IA	IPC	CW13		
Zeigler Coal Co.	Spartan	6	Randolph (Sparta)	8-12			10,900	107.1CE	Joppa, IL	EEI	CW18	728,877	843,114
							11,000	107.9C	Joppa, IL	EEI	CW23		
					10.3	3.1	11,100	107.5C	Joppa, IL	EEI	CW28		
							10,800	106.3NC	Joppa, IL	EEI	CW3		
							10,900	106.4C	Joppa, IL	EEI	CW14		
							11,000	106.6C	Joppa, IL	EEI	CW10		

Illinois (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Consolidation Coal Co.	Burning Star #2(S)	6	Perry (DuQuoin)	8-12			10,500	81.3S	Bartonville, IL	CILC	K-CW3	1,107,733	1,431,994
							10,300	65.3S	Joppa, IL	EEC	CW3		
							10,800	92.5C	Clinton, IA	IPC	CW23		
							10,600	92.0C	Dubuque, IA	IPC	CW23		
							11,000	82.4S	Bartonville, IL	CILC	CW23		
							11,000	73.8S	East Peoria, IL	CILC	CW23		
							11,000	77.0S	East Peoria, IL	CILC	CW21		
							11,000	89.0C	Cassville, WI	WSPLC	CW21		
							10,800	95.5C	Genoa, WI	DPC	CW21		
							11,200	44.2CE	Labadie, MO	UEC	CW20		
							11,200	47.0C	St. Louis, MO	UEC	CW20		
							11,200	44.4CE	Labadie, MO	UEC	CW17		
							11,200	47.0CE	St. Louis, MO	UEC	CW17		
							10,900	96.1C	Alma, WI	DPC	CW14		
							10,900	94.4C	Genoa, WI	DPC	CW14		
							10,900	90.2C	Cassville, WI	WSPLC	CW14		
							11,200	48.6CE	St. Charles, MO	UEC	CW12		
							11,200	44.4CE	Labadie, MO	UEC	CW12		
							11,100	78.9S	Bartonville, IL	CILC	CW10		
					10.8	3.1	11,100	93.5C	Genoa, WI	DPC	CW30		
					8.0	3.5	11,000	85.4S	East Peoria, IL	CILC	CW30		
					9.4	3.5	11,100	93.0S	Bartonville, IL	CILC	CW30		
					10.7	3.1	11,200	91.1C	Cassville, WI	WSPLC	CW30		
					10.1	3.1	11,200	50.4CE	St. Louis, MO	UEC	CW32		
					10.1	3.1	11,200	50.9CE	St. Louis, MO	UEC	CW32		
					10.1	3.1	11,500	52.0CE	West Alton, MO	UEC	CW32		
					10.1	3.1	11,200	48.8CE	Labadie, MO	UEC	CW32		
					8.0	3.5	11,000	96.9S	East Peoria, IL	CILC	CW34		
					9.9	3.4	11,400	89.3C	Cassville, WI	DPC	CW34		
					9.9	3.4	11,400	91.0C	Genoa, WI	DPC	CW34		
Midland Coal Co.	Allendale(S)	6	Stark (Wyoming)	16-20	14.5	3.6	10,700	126.0CE	Bettendorf, IA	IIGEC	K-CW6	253,366	379,038
Freeman-United Coal Mining Co.	Orient #3(D)	6	Jefferson (Walton-ville)	7-10	7-10	1-3	10,900	109.9S	Springfield, IL	SWLPD	K-CW6	1,919,297	2,207,429

Illinois (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10⁶ Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Freeman-United Coal Mining Co.	Orient #6(D)	6	Jefferson (Waltonville)	7-10	7.3	1.3	11,800	66.5C	St. Louis, MO	UEC	K-CW24	1,678,028	1,829,970
							12,000	139.7CE	Columbia, MO	CWLD	CW3		
							11,800	66.2C	St. Louis, MO	UEC	CW20		
							11,800	68.0CE	St. Louis, MO	UEC	CW20		
							11,700	33.8CE	Columbia, MO	CWLD	CW18		
							11,800	66.2CE	St. Louis, MO	UEC	CW17		
							11,800	66.2CE	St. Louis, MO	UEC	CW12		
							11,800	131.3CE	Columbia, MO	CWLD	CW12		
					7,3	1,3	11,800	67.1CE	St. Louis, MO	UEC	CW32		
					7,3	1.3	11,800	66.5C	St. Louis, MO	UEC	CW32		
					7.3	1.3	11,800	69.9CE	St. Louis, MO	UEC	CW32		
Freeman-United Coal Mining Co.	Orient #4 (D)	6	Williamson (Marion)	4-9	11.2	2.6	11,700	81.1CE	Joppa, IL	EEI	K-CW23	962,359	1,254,290
							11,600	81.1C	Joppa, IL	EEI	CW28		
							11,600	78.3CE	Joppa, IL	EEI	CW18		
							11,300	69.8CE	Joppa, IL	EEI	CW3		
							11,600	75.4CE	Joppa, IL	EEI	CW14		
							11,600	72.6CE	Joppa, IL	EEI	CW10		
Midland Coal Co.	Mecco(S)	6	Knox (Victoria)	16-20			10,000	66.2CE	Burlington, IA	ISUC	K-CW4	1,017,046	1,015,777
							10,100	66.1CE	Burlington, IA	ISUC	CW8		
							10,600	95.6S	Monteplier, IA	EIPLC	CW8		
							10,400	67.2CE	Bettendorf, IA	IIGEC	CW6		
							10,000	66.3CE	Burlington, IA	ISUC	CW6		
					7.6	2.4	10,200	68.5CE	Burlington, IA	ISUC	CW28		
					7.7	2.9	10,400	93.9S	Montpelier, IA	EILPC	CW28		
							10,200	62.7CE	Burlington, IA	ISUC	CW23		
							10,600	68.0CE	Bettendorf, IA	IIGEC	CW23		
							10,300	94.8S	Montpelier, IA	EILPC	CW18		
							10,600	66.4CE	Bettendorf, IA	IIGEC	CW18		
							10,500	93.4S	Montpelier, IA	EILPC	CW12		
							10,500	67.0CE	Bettendorf, IA	IIGEC	CW11		
					7.7	2.7	10,500	76.2CE	Bettendorf, IA	IIGEC	CW30		
					7.5	2.5	10,500	93.8S	Montpelier, IA	EILPC	CW34		
					8.8	3.2	10,500	76.5CE	Bettendorf, IA	IIGEC	CW34		
					7.6	2.4	10,200	68.8CE	Burlington, IA	ISUC	CW34		
							10,200	63.3CE	Burlington, IA	ISUC	CW13		

Illinois (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Sahara Coal Co.	#6(S)	6	Saline (Harrisburg)	14-9	8.5	2.2	12,200	93.4S	Grand Tower, IL	CIPSC	K-CW24	993,881	887,578
				6.8	7.6	1.9	12,300	93.2S	Hutsonville, IL	CIPSC	CW24		
					7.3	2.1	12,400	101.6CE	Cedar Falls, IA	CFMUC	CW24		
							12,200	81.0CE	Joppa, IL	EEI	CW3		
							12,300	79.3S	Hutsonville, IL	CIPSC	CW3		
							10,700	85.6S	Marion, IL	SIPC	CW5		
							10,800	83.5C	Marion, IL	SIPC	CW7		
							12,400	125.7S	Humboldt, IA	CBPC	CW28		
							12,100	82.7C	Joppa, IL	EEI	CW28		
							12,300	82.7C	Joppa, IL	EEI	CW23		
							12,600	98.5CE	Charlevoix, MI	CPC	CW23		
							12,200	93.8S	Hutsonville, IL	CIPSC	CW21		
							12,700	98.8CE	Cedar Falls, IA	CFMUC	CW18		
							12,300	82.7CE	Joppa, IL	EEI	CW18		
							12,500	98.5C	Menasha, WI	MEWUC	CW18		
							12,500	97.4CE	Cedar Falls, IA	CFMUC	CW17		
							12,300	81.0C	Joppa, IL	EEI	CW14		
							12,300	106.2S	Grand Tower, IL	EEI	CW11		
							12,200	81.0C	Joppa, IL	EEI	CW10		
					7.2	2.3	12,700	97.8CE	Boyne City, MI	NMEC	CW32		
					7.2	1.8	12,000	95.7S	Hutsonville, IL	CIPSC	CW32		
					7.7	2.3	12,600	108.8CE	Boyne City, MI	NMEC	CW34		
					7.5	1.8	12,400	125.4S	Humboldt, IA	CBPC	CW34		
					7.7	2.0	12,600	121.5S	Spencer, IA	CBPC	CW34		
					7.1	2.6	12,900	113.0C	Menasha, WI	MEWUC	CW34		
Amax Coal Co.	Delta(S)	6	Williamson (Marion)	4-9			11,100	117.1S	Grand Tower, IL	CIPSC	K-CW3	907,008	921,015
							11,500	99.0S	Joppa, IL	EEI	CW3		
							11,700	111.6S	Hutsonville, IL	CIPSC	CW3		
					12.1	3.0	11,700	99.0S	Joppa, IL	EEI	CW28		
							11,600	99.0S	Joppa, IL	EEI	CW23		
							11,500	131.3C	Rothschild, WI	WPSC	CW20		
							11,600	99.0S	Joppa, IL	EEI	CW18		
							11,500	130.7C	Rothschild, WI	WPSC	CW17		
							11,400	99.0S	Joppa, IL	EEI	CW14		
							11,400	113.7S	Grand Tower, IL	CIPSC	CW11		
							11,100	99.0S	Joppa, IL	EEI	CW10		
					10.3	2.9	11,600	126.8NC	Holland, MI	HPW	CW34		

Illinois (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10⁶ Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Amax Coal	Leahy(S)	5 & 6	Jackson	7-10	11.0	3.4	11,000	61.1CE	Michigan City, IN	NIPSCO	K-CW24	2,834,134	2,942,035
Co.			(Campbell				10,700	52.7CE	Gary, IN	NIPSCO	CW1		
			Hill)		11.3	3.2	10,500	60.0CE	LaPorte, IN	NIPSCO	CW28		
							11,200	40.8CE	Labadie, MO	UEC	CW20		
							11,200	41.0CE	Labadie, MO	UEC	CW17		
							11,200	41.0CE	Labadie, MO	UEC	CW12		
					8.6	2.9	11,200	42.2CE	Labadie, MO	UEC	CW32		
					8.6	2.9	11,200	42.0C	Labadie, MO	UEC	CW32		
Southwestern	Captain (S)	6	Randolph	8-12	9.9	3.1	11,300	97.8S	Coffeen, IL	CIPSC	K-CW24	4,346,970	4,451,313
Illinois			(Percy)		9.9	3.2	11,300	79.4C	Grand Tower, IL	CIPSC	CW24		
Coal Corp.					14.3	3.7	10,200	93.0C	Meredosia, IL	CIPSC	CW24		
					13.3	3.5	10,800	82.6C	Joliet, IL	CE	CW24		
					13.9	3.6	10,400	107.1S	Dune Acres, IN	NIPSCO	CW24		
					10.5	3.7	10,800	80.7C	St. Louis, MO	UEC	CW24		
					10.5	3.7	10,800	79.7C	St. Charles, MO	UEC	CW24		
							10,400	97.7S	Michigan City, IN	NIPSCO	CW9		
							10,500	96.3S	Michigan City, IN	NIPSCO	CW1		
							10,900	70.3C	Pearl, IL	CIPSC	CW5		
							10,500	96.3C	Dune Acres, IN	NIPSCO	CW1		
							10,900	93.4C	Clinton, IA	IPC	CW23		
							11,300	79.6C	Grand Tower, IL	CIPSC	CW21		
							10,400	91.1C	Meredosia, IL	CIPSC	CW21		
							10,800	75.5CE	Labadie, MO	UEC	CW20		
							10,800	79.7C	St. Charles, MO	UEC	CW20		
							10,800	81.8C	St. Louis, MO	UEC	CW20		
							10,800	82.2CE	St. Louis, MO	UEC	CW20		
							11,000	90.4C	Pearl, IL	WIPC	CW20		
							10,800	42.8C	Joliet, IL	CE	CW18		
							11,200	90.8C	Clinton, IA	IPC	CW18		
							10,800	79.7CE	St. Charles, MO	UEC	CW17		
							10,800	81.8CE	St. Charles, MO	UEC	CW17		
							10,800	80.6CE	St. Charles, MO	UEC	CW17		
							10,800	44.7C	Joliet, IL	CE	CW14		
							10,800	80.6CE	St. Louis, MO	UEC	CW12		
							10,800	77.7CE	St. Louis, MO	UEC	CW12		
							10,900	63.9C	Pearl, IL	WIPC	CW12		
							10,600	95.4C	Clinton, IA	IPC	CW11		
							10,800	36.8C	Hammond, IN	CE	CW10		
							10,800	40.1C	Joliet, IL	CE	CW10		
					15.0	3.8	10,600	45.4C	Joliet, IL	CE	CW30		
					10.5	3.7	10,800	76.8C	Labadie, MO	UEC	CW32		
					9.9	3.1	11,300	97.8S	Coffeen, IL	CIPSC	CW32		
					10.5	3.7	10,800	82.6CE	St. Louis, MO	UEC	CW32		
					10.5	3.7	10,800	80.7C	St. Louis, MO	UEC	CW32		
					10.5	3.7	10,800	79.6C	West Alton, MO	UEC	CW32		
							10,900	93.3C	Clinton, IA	IPC	CW13		
							10,800	36.8C	Hammond, IN	CE	CW3		

Illinois (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Southwestern Illinois Coal Corp.	Streamline(S)	6	Randolph (Percy)	8-12	11.1	3.2	10,600	104.8S	Dune Acres, IN	NIPSCO	K-CW24	1,215,383	1,445,733
					11.1	3.2	10,600	106.3S	Michigan City, IN	NIPSCO	CW24		
							10,900	93.9S	Newnan, GA	GAPC	CW7		
							10,900	85.3S	Newnan, GA	GAPC	CW3		
							10,500	95.8S	Michigan City, IN	NIPSCO	CW1		
							10,700	94.7S	Michigan City, IN	NIPSCO	CW9		
							11,100	81.4CE	St. Louis, MO	UEC	CW20		
							11,100	80.9CE	St. Louis, MO	UEC	CW17		
							11,100	79.8CE	St. Louis, MO	UEC	CW12		
					10.3	3.3	11,200	81.0C	Grand Tower, IL	CIPSC	CW32		
					14.6	3.5	10,400	92.6C	Meredosia, IL	CIPSC	CW32		
					11.5	3.3	11,100	81.7C	St. Louis, MO	UEC	CW32		
Zeigler Coal Co.	Murdock(D)	6	Douglas (Murdock)		12.7	2.3	10,300	71.5CE	Michigan City, IN	NIPSCO	CW24	1,296,854	1,531,716
							10,900	93.0C	Springfield, IL	SWLPD	CW13		
							10,900	93.0C	Springfield, IL	SWLPD	CW6		
							10,900	116.1C	Rothschild, WI	WIPSC	CW5		
					15.0	2.8	10,300	68.2CE	Michigan City, IN	NIPSCO	CW28		
					10.3	2.6	10,500	112.9C	Springfield, IL	SWLPC	CW28		
							10,500	112.9C	Springfield, IL	SWLPC	CW23		
							10,500	112.9C	Springfield, IL	SWLPC	CW23		
							10,700	127.2C	Rothschild, WI	WIPSC	CW20		
							10,900	93.0C	Springfield, IL	SWLPC	CW18		
							10,600	126.6NC	Rothschild, WI	WIPSC	CW17		
							10,500	120.3C	Rothschild, WI	WIPSC	CW12		
							10,900	93.0C	Springfield, IL	SWLPC	CW12		
					11.5	4.3	10,600	131.0C	Rothschild, WI	WIPSC	CW32		
					10.3	2.6	10,500	112.9C	Springfield, IL	SCWLP	CW34		
							10,900	93.0C	Springfield, IL	SWLPD	CW3		
Zeigler Coal Co.	Zeigler #4	6	Williamson (Johnson City)	4-9	10.3	2.6	11,700	92.6C	Joppa, IL	EEI	K-CW23	580,903	423,211
							11,700	97.1CE	Joppa, IL	EEI	CW28		
							11,700	92.6CE	Joppa, IL	EEI	CW18		
							11,400	92.4NC	Joppa, IL	EEI	CW3		
							11,200	92.4C	Joppa, IL	EEI	CW14		
							11,400	92.4C	Joppa, IL	EEI	CW10		

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10⁶ Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Freeman-United Coal Mining Co.	Buckheart #17(S)	5	Fulton (Canton)	14-18			10,200	57.1C	Bartonville, IL	CILC	K-CW3	1,118,879	1,253,473
							9,800	114.5S	Burlington, IA	ISUC	CW8		
							10,200	59.7C	East Peoria, IL	CILC	CW8		
							10,000	58.2C	Bartonville, IL	CILC	CW8		
							10,100	59.7C	East Peoria, IL	CILC	CW6		
							10,100	58.0C	Bartonville, IL	CILC	CW6		
							10,200	67.0CE	Muscatine, IA	MMEP	CW23		
							9,900	58.7C	Bartonville, IL	CILC	CW23		
							10,600	120.6CE	Bettendorf, IA	IIGEC	CW23		
							10,500	57.5C	East Peoria, IL	CILC	CW21		
							9,600	60.6C	Bartonville, IL	CILC	CW21		
							10,300	124.5CE	Bettendorf, IA	IIGEC	CW18		
							10,200	67.0CE	Muscatine, IA	MMEP	CW18		
							10,200	59.2C	East Peoria, IL	CILC	CW14		
							10,300	134.7CE	Bettendorf, IA	IIGEC	CW11		
							10,200	59.7C	East Peoria, IL	CILC	CW10		
							10,000	58.2C	Bartonville, IL	CILC	CW10		
					12.0	3.4	12,000	123.4CE	Bettendorf, IA	IIGEC	CW30		
					13.0	3.5	9,900	59.1C	Bartonville, IL	CILC	CW30		
					9.0	3.0	10,200	67.0C	Muscatine, IA	MMEP	CW30		
					13.2	2.4	9,900	59.7C	Bartonville, IL	CILC	CW34		
					11.9	3.3	10,300	126.7CE	Bettendorf, IA	IIGEC	CW34		
					9.7	3.0	10,200	67.4CE	Muscatine, IA	MMEP	CW34		
							9,900	115.9S	Burlington, IA	ISUC	CW13		
							10,200	67.0C	Muscatine, IA	MMEP	CW13		
United Electric Coal Co.	Fidelity #11 (S)	6	Perry (Duquoin)	8-12			11,100	109.1C	Joppa, IL	EEI	CW18	1,206,918	1,639,003
							11,200	58.0CE	Muscatine, IA	MMEP	CW18		
							11,200	59.4C	Lansing, IA	IPC	CW18		
							10,800	55.3CE	Grand Tower, IL	CIPSC	CW21		
							11,200	58.0CE	Muscatine, IA	MMEP	CW23		
							11,400	109.1C	Joppa, IL	EEI	CW23		
					12.2	3.8	11,000	55.3CE	Grand Tower, IL	CIPSC	CW24		
							10,900	121.7S	Joppa, IL	EEI	CW3		
							10,700	57.5CE	Grand Tower, IL	CIPSC	CW3		
							10,900	109.1C	Joppa, IL	EEI	CW14		
							10,600	55.3CE	Grand Tower, IL	CIPSC	CW11		
							11,000	54.4NC	Joppa, IL	EEI	CW10		
					9.7	3.0	11,200	58.0CE	Muscatine, IA	MMEP	CW30		
					12.4	3.6	10,800	55.3CE	Grand Tower, IL	CIPSC	CW32		
					9.7	3.0	11,200	58.4CE	Muscatine, IA	MMEP	CW34		
							11,100	59.7C	Lansing, IA	IPC	CW13		
							11,200	58.0CE	Muscatine, IA	MMEP	CW13		

Illinois (Contd.)

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ALPC - Alabama Power Company
AEC - Associated Electric Coop
CFMUC - Cedar Falls Municipal Utility Company
CILC - Central Illinois Light Company
CIPSC - Central Illinois Public Service Company
CWLD - Columbia Water and Light Department
CE - Commonwealth Edison
CPC - Consumers Power Company
CBPC - Corn Belt Power Coop
DPC - Dairyland Power Coop
EIPLC - Eastern Iowa Power and Light Company
EEI - Electric Energy, Inc.
GAPC - Georgia Power Company
GPC - Gulf Power Company
HPW - Holland Public Works

IPC - Interstate Power Company
IIGEC - Iowa-Illinois Gas and Electric Company
ISUC - Iowa Southern Utility Company
MEWUC - Menasha Electric and Water Utility Company
MSPC - Mississippi Power Company
MMEP - Muscatine-Muni Electric Plant
NIPSCO - Northern Indiana Public Service Company
NMEC - Northern Mississippi Electric Company
SCWLPC - South Central Wisconsin Light and Power Company
SIPC - Southern Illinois Power Coop
SWLPC - Springfield Water, Light, and Power Department
TVA - Tennessee Valley Authority
UEC - Union Electric Company
WIPC - Western Illinois Power Coop
WSPLC - Wisconsin Power and Light Company
WIPSC - Wisconsin Public Service Company

Table B.2. Coal Mine Data: Western States

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							Arizona						
Peabody Coal Company	Black Mesa(S) (C)	Black Mesa	Navajo (Kayenta)	3.4- 17.4	8.0 8.9	.6	11,000	27.3C	Clark Co., NV	NVPC	K-CW17	3,933,493	3,246,500
							Colorado						
Energy Fuel Corp.	Energy #1(S)	Wadge	Routt (Steam Boat Springs)	9.0- 10.0	7.1- 7.3	.4- .5	10,900	43.2C	Denver, CO	PSCC	K-CW20	1,240,150	701,973
							10,900	62.4C	Palisade, CO	PSCC	CW20		
							10,400	45.2C	Denver, CO	PSCC	CW11		
Pittsburgh-Midway Coal Mfg. Co.	Edna(S)	Wadge	Routt (Oak Creek)	7.7- 11.8			10,800	36.5C	Denver, CO	PSCC	K-CW20	1,134,068	1,076,120
							10,800	51.7C	Col. Spr., CO	CCS	CW20		
					16.9	.7	10,200	91.5C	Canon City, CO	CTUC	CW33		
Empire Energy Corp.	Wise Hill #5 (S)(D)	Campbell	Moffat (Craig)	17.1- 20.5			10,000	141.3S	Cedar Rapids, IA	IELPC	K-CW20	214,046	183,659
							9,900	141.5S	Marshalltown, IA	IELPC	CW20		
							8,500	116.4C	Col. Spr., CO	CCS	CW20		
							10,400	129.6S	Cedar Rapids, IA	IELPC	CW5		
							10,200	105.4C	Bellevue, NB	NPPD	CW5		
					9.1	0.4	9,900	87.3C	Col. Spr., CO	CCS	CW33		
					10.5	0.5	9,800	92.7C	Col. Spr., CO	CCS	CW33		
					9.5	0.4	9,000	154.1S	Boone, IA	IELPC	CW33		
					9.5	0.4	10,000	141.8S	Prairie Creek, IA	IELPC	CW33		
					4.0	0.7	9,900	81.4C	Bellevue, NB	NPPD	CW33		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							Colorado (Contd.)						
Imperial Coal Co.	Eagle (D)	Laramie #3	Weld (Erie)	33.1-35.0	7.8-15.7	.4	9,300	54.1C	Denver, CO	PSCC	K-CW20	167,909	225,590
							9,300	54.1C	Denver, CO	PSCC	CW11		
							Montana						
Decker Coal Co.	Decker #1(S)	Anderson-Dietz 1 & 2	Big Horn	23.0			9,700	82.4C	Hammond, IN	CE	K-CW10	6,786,000	4,159,287
							9,700	86.3C	Joliet, IL	CE	CW10		
							9,700	87.5C	Waukegan, IL	CE	CW10		
							9,700	77.2C	Pekin, IL	CE	CW10		
							9,700	87.6C	Chicago, IL	CE	CW10		
					4.3	.5	9,600	86.4C	Chicago, IL	CE	CW26		
					4.3	.5	9,600	82.6C	Joliet, IL	CE	CW26		
					4.3	.5	9,600	84.0C	Chicago, IL	CE	CW26		
					4.3	.5	9,600	86.1C	Joliet, IL	CE	CW26		
					4.3	.5	9,600	75.2C	Pekin, IL	CE	CW26		
							9,700	86.0C	Joliet, IL	CE	CW20		
							9,700	84.2C	Pekin, IL	CE	CW20		
							9,700	79.7C	Joliet, IL	CE	CW20		
							9,700	86.4C	Chicago, IL	CE	CW20		
							9,600	75.5C	Pekin, IL	CE	CW15		
							9,600	80.1C	Joliet, IL	CE	CW15		
							9,600	89.3C	Chicago, IL	CE	CW15		
							9,600	81.5C	Hammond, IN	CE	CW15		
							9,600	82.6C	Waukegan, IL	CE	CW15		
					4.0	.4	9,700	88.2C	Hammond, IN	CE	CW33		
					4.0	.4	9,700	89.1C	Romeoville, IL	CE	CW33		
					4.0	.4	9,700	84.9C	Waukegan, IL	CE	CW33		
					4.0	.4	9,700	90.3C	Chicago, IL	CE	CW33		
					4.0	.4	9,700	89.6C	Chicago, IL	CE	CW33		

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							Montana (Contd.)						
Western Energy Co.	Colstrip(S)(C)	Rosebud	Rosebud (Colstrip)	25.5			8,800	84.4S	Ashland, WI	LSDPC	K-CW8	3,213,000	4,253,681
							8,700	81.5S	Stanton, ND	BEPC	CW8		
					8.7	.8	8,500	91.7C	Joliet, IL	CE	CW26		
							8,500	92.2S	Ashland, WI	LSDPC	CW20		
							8,600	90.0C	Joliet, IL	CE	CW20		
							8,700	90.9C	Joliet, IL	CE	CW10		
							8,600	90.8C	Joliet, IL	CE	CW15		
Peabody Coal Co.	Big Sky(S)	McKay Rosebud	Rosebud (Colstrip)	26.3			8,700	34.6CE	Cohasset, MN	MPLC	K-CW1	2,228,524	1,971,643
							7,900	53.0CE	Aurora, MN	MPLC	CW1		
							8,500	38.9C	Cohasset, MN	MPLC	CW23		
							8,300	54.4C	Aurora, MN	MPLC	CW23		
					9.8	1.3	8,200	61.5CE	Aurora, MN	MPLC	CW33		
					8.5	1.4	8,500	43.8CE	Cohasset, MN	MPLC	CW33		
Westmoreland Resources	Sarpy Creek(S)	Rosebud-McKay & Robinson	Big Horn (Hardin)	25.0			8,900	105.2C	Bartonville, IL	CILC	K-CW 8	1,457,673	Opened 7/1/74
							7,800	119.7C	Bartonville, IL	CILC	CW 6		
							8,400	113.9C	Bartonville, IL	CILC	CW23		
							8,700	106.3C	E. Peoria, IL	CILC	CW23		
							8,600	76.3C	Stanton, ND	BEPC	CW17		
							8,400	101.7C	E. Peoria, IL	CILC	CW15		
							8,800	105.8C	Bartonville, IL	CILC	CW15		
					8.3	.4	8,500	117.0C	Bartonville, IL	CILC	CW33		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							Montana (Contd.)						
Knife River Coal Co.	Savage (S)	Breezy Flat	Richland (Savage)	38.0	8.4	.7	6,400	43.9CE	Sidney, MT	MDUC	K-CW26	329,590	312,785
							6,500	43.4CE	Sidney, MT	MDUC	CW20		
							6,400	43.6CE	Sidney, MT	MDUC	CW8		
							6,400	43.8CE	Sidney, MT	MDUC	CW1		
							New Mexico						
Utah Int'l., Inc.	Navajo(S) (C)	#6,7,&8	San Juan (Fruitland)	13.2			8,800	92.7S	Joseph City, AZ	APSC	K-CW11	6,955,000	7,389,321
							8,800	20.4CE	Fruitland, NM	PSCNM	CW11		
					23.1	.5	8,700	21.6CE	Farmington, NM	APSC	CW33		
					23.1	.5	8,700	18.8S	Navajo, AZ	SRP	CW33		
							North Dakota						
Knife River Coal Co.	Beulah(S)	Beulah-Zap	Mercer (Beulah)	36.0			6,800	32.8CE	Mandan, ND	MDUC	K-CW1	1,722,079	1,726,000
							6,900	57.5C	Fergus Falls, MN	OTPC	CW5		
							7,000	32.2CE	Mandan, ND	MDUC	CW8		
					7.0	1.0	7,000	32.8CE	Mandan, ND	MDUC	CW26		
					6.9	.7	7,100	59.0C	Fergus Fall, MN	OTPC	CW33		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							North Dakota (Contd.)						
Baukol-	Center(S)	Hagel	Oliver	33.5-			6,700	12.8CE	Center, ND	MPC	K-CW5	1,595,378	1,563,446
Noonan, Inc.			(Center)	43.8	7.0	.7	6,500	17.5CE	Center, ND	MPC	CW33		
North	Indian Head(S)	Zap	Mercer	33.5-			6,500	22.3CE	Stanton, ND	UPA	K-CW5	1,270,254	1,090,144
American			(Beulah)	43.8	9.2	.7	6,900	19.6CE	Stanton, ND	UPA	CW33		
Coal Corp.							6,900	19.2CE	Stanton, ND	UPA	CW8		
					10.1	.8	6,900	19.3CE	Stanton, ND	UPA	CW26		
Consolidation	Velva(S)	Coteau	McHenry	37.9	5.9	.4	6,600	35.6C	Velva, ND	BEPC	K-CW26	548,012	452,050
Coal Co.			(Velva)				6,600	29.7S	Velva, ND	BEPC	CW1		
							Utah						
Peabody	Deer Creek	Blind	Emery	.7-			12,600	42.8C	Moapa, NV	NVPC	K-CW4	1,047,671	489,887
Coal Co.	(D)	Canyon	(Hunt-	14.5			12,200	38.3CE	Huntington Cy,UT	UPL	CW8		
		(Wasatch	ington)				12,600	52.1C	Moapa, NV	NVPC	CW8		
		Plateau					12,600	79.8C	Moapa, NV	NVPC	CW22		
		Field)					12,100	36.7CE	Huntington Co,UT	UPL	CW20		
							12,600	71.4C	Moapa, NV	NVPC	CW15		
					7.0	.5	12,600	82.2C	Moapa, NV	NVPC	CW31		
					7.8	.5	12,200	36.8CE	Huntington Co,UT	UPL	CW26		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							Utah Contd.)						
Carbon Fuel Co.	Carbon Fuel (D)	Castle-gate "B"	Carbon (Helper)	5.0	8.0	.3	12,000	154.4S	Brilliant, OH	OPC	K-CW6		395,217
							12,200	117.0C	Lawrenceburg, IN	IMEC	CW4		
							12,100	148.1C	Brilliant, OH	OPC	CW6		
							11,600	157.3C	Lawrenceburg, IN	IMEC	CW11		
American Coal Co.	Deseret (D)	Wasatch Plateau Field	Emery (Hunt-ington)	6.1-14.5	11.3	.4	11,500	45.6CE	Castle Gate, UT	UPL	K-CW26	870,595	925,000
					11.3	.4	11,500	55.9CE	Salt Lake City,UT	UPL	CW26		
					11.3	.4	11,500	58.7C	Orem, UT	UPL	CW26		
							12,400	80.9C	Moapa, NV	NVPC	CW22		
							11,400	62.0CE	Orem, UT	UPL	CW20		
							11,400	56.5CE	Salt Lake City,UT	UPL	CW20		
							11,300	46.3CE	Castle Gate, UT	UPL	CW20		
							10,900	54.5CE	Castle Gate, UT	UPL	CW8		
							11,000	65.0CE	Salt Lake City,UT	UPL	CW8		
							10,900	72.0CE	Orem, UT	UPL	CW8		
							12,400	80.7C	Moapa, NV	NVPC	CW15		
					7.0	.5	12,400	83.8C	Moapa, NV	NVPC	CW31		
Coop. Mining	Coop	Wasatch Plateau Field	Carbon (Price)	6.1-14.5	7.0	.5	12,400	86.2C	Moapa, NV	NVPC	K-CW26		100,000
							12,400	80.9C	Moapa, NV	NVPC	CW22		
							12,400	84.9C	Moapa, NV	NVPC	CW15		
					7.0	.5	12,400	84.0C	Moapa, NV	NVPC	CW31		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							Utah (Contd.)						
U.S. Fuel Co.	King(D)	Hiawatha	Carbon (Hiwatha)	6.1-14.5	7.0	.5	12,400	83.9C	Moapa, NV	NVPC	K-CW31	537,424	569,854
							Wyoming						
Resources Exploration & Mining, Inc. (Strip Contractors for Energy Development)	Hanna (S)	Brooks	Carbon (Hanna)	13.66	9.9	.7	10,200	63.6CE	Omaha, NB	OPPD	K-CW24	594,070	625,000
							10,400	58.0CE	Omaha, NB	OPPD	CW1		
							10,500	57.8S	Omaha, NB	OPPD	CW9		
					9.2	.8	10,600	63.0CE	Omaha, NB	OPPD	CW28		
					9.9	.7	10,200	63.6CE	Omaha, NB	OPPD	CW28		
							10,200	61.4CE	Omaha, NB	OPPD	CW19		
							10,500	59.5CE	Omaha, NB	OPPD	CW14		
					8.1	.9	10,800	80.9CE	Omaha, NB	OPPD	CW36		
Arch Minerals Co.	Seminole #1(S)	#25	Carbon (Hanna)	13.96	9.0	.3	9,900	66.9C	Sioux City, IA	IPSC	K-CW24	3,142,400	2,865,100
							10,100	48.6C	Kansas City, MO	KCPL	CW9		
							10,100	79.0C	Kansas City, MO	KCPL	CW9		
							10,100	61.0C	Sioux City, IA	IPSC	CW5		
							9,800	87.3S	Lake Co., IN	CE	CW1		
							10,100	60.6C	Sioux City, IA	IPSC	CW9		
					11.0	.7	10,300	49.1C	Kansas City, MO	KCPL	CW28		
					8.7	1.0	10,900	102.3S	Kansas City, MO	KCPL	CW28		
					9.2	.4	9,500	103.9C	Lancaster Co., NB	LES	CW27		
					9.0	.3	9,900	66.9C	Sioux City, IA	IPSC	CW24		
							9,900	49.1C	Kansas City, MO	KCPL	CW23		
							9,500	97.6C	Columbus, NB	SDU	CW22		
							9,700	72.2C	Hammond, IN	CE	CW22		
							10,000	49.1CE	Kansas City, MO	KCPL	CW18		
							9,700	66.9C	Waukegan, IL	CE	CW18		
							10,800	114.6CE	Bettendorf, IA	IIGEC	CW15		
							10,300	49.1CE	Kansas City, MO	KCPL	CW14		
							9,900	64.6C	Dixon, IL	CE	CW11		
							9,900	64.5C	Waukegan, IL	CE	CW11		
							9,900	70.9C	Hammond, IN	CE	CW11		
					9.5	.4	9,800	73.4C	Hammond, IN	CE	CW33		
					9.5	.4	9,800	66.8C	Waukegan, IL	CE	CW33		
					10.7	.6	10,300	64.3C	Salix, IA	IPSC	CW34		
					15.2	.3	8,900	123.1C	Hallam, NB	NPPD	CW36		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Wyoming (Contd.)													
Arch Minerals Co.	Seminole #2(S)	Hanna #2	Carbon (Hanna)	7.5-12.7	13.4	.4	9,800	97.7CE	Omaha, NB	OPPD	K-CW24	2,589,752	1,497,675
							10,400	92.6S	Omaha, NB	OPPD	CW9		
							10,600	91.0S	Omaha, NB	OPPD	CW1		
							10,400	92.6S	Omaha, NB	OPPD	CW8		
							10,600	81.7S	Kansas City, KS	KCBPU	CW5		
							10,700	89.2CE	Hallam, NB	NPPD	CW8		
							10,400	89.5C	Independence, MO	IPLD	CW5		
					10.1	.8	10,600	99.3CE	Omaha, NB	OPPD	CW28		
					11.2	.6	10,500	105.9S	Kansas City, KS	KCBPU	CW28		
					13.4	.4	9,800	97.7CE	Omaha, NB	OPPD	CW24		
							9,800	92.6C	Kansas City, KS	KCBPU	CW23		
							9,800	100.5C	Columbus, NB	SDU	CW22		
							10,900	89.7C	Independence, MO	IPLD	CW22		
							10,400	90.8CE	Omaha, NB	OPPD	CW19		
							10,100	90.3S	Kansas City, KS	KCBPU	CW18		
							10,600	89.7C	Independence, MO	IPLD	CW15		
							10,700	84.8S	Kansas City, KS	KCBPU	CW14		
							10,700	93.2CE	Omaha, NB	OPPD	CW14		
							10,000	91.0S	Kansas City, KS	KCBPU	CW12		
							10,300	92.3C	Independence, MO	IPLD	CW12		
					11.7	.6	10,500	100.0CE	Omaha, NB	OPPD	CW36		
					9.7	.6	10,700	103.7S	Kansas City, KS	KCBPU	CW36		
Amax Coal Co.	Belle Ayr(S)	Roland-Smith	Campbell (Gillette)	22.3-32.8			8,400	33.5C	Pueblo, CO	PSCC	K-CW1	3,312,858	897,507
							8,700	94.7S	Cayuga, IN	IMEC	CW5		
					6.9	.4	8,300	86.8S	Burlington, IA	ISUC	CW28		
					6.5	.6	8,200	71.7C	Pleasant Hill, IA	IPLD	CW27		
							8,500	34.8C	Pueblo, CO	PSCC	CW22		
							8,500	51.8C	Denver, CO	PSCC	CW22		
							8,400	71.1C	Pleasant Hill, IA	IPLD	CW18		
							8,600	49.5C	Denver, CO	PSCC	CW15		
							8,800	33.2C	Pueblo, CO	PSCC	CW15		
							9,200	82.0S	Gallipolis, OH	OVEC	CW14		
							8,600	49.5C	Denver, CO	PSCC	CW11		
					6.3	.5	8,300	72.3C	Des Moines, IA	IPLD	CW34		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
Wyoming (Contd.)													
Arch Minerals Corp.	Medicine Bow (S)	Hanna Field	Carbon (Medicine Bow)	7.5-	11.7	.6	9,400	80.9C	Lake County, IN	NIPSCO	K-CW28	3,000,000	
				12.7	13.1	.5	9,500	81.1CE	Lake County, IN	NIPSCO	CW27		
					14.9	.5	9,600	99.9CE	Lawrence, KS	KSPL	CW27		
					13.7	.5	9,800	98.3CE	Tecumseh, KS	KSPL	CW27		
							9,900	99.4CE	Tecumseh, KS	KSPL	CW22		
							9,800	98.0CE	Lawrence, KS	KSPL	CW22		
							9,500	80.7CE	Lake County, IN	NIPSCO	CW19		
							9,800	74.6CE	Lake County, IN	NIPSCO	CW9		
							9,500	72.1CE	Lake County, IN	NIPSCO	CW1		
							9,700	77.8CE	Lake County, IN	NIPSCO	CW15		
							9,900	92.9NC	Lawrence, KS	KSPL	CW12		
							9,900	99.9CE	Tecumseh, KS	KSPL	CW33		
							9,800	101.1CE	Lawrence, KS	KSPL	CW33		
Pacific Power & Light Co.	Jim Bridger (S) (C)	Deadman	Sweetwater (Rock Springs)	20.5			9,600	23.6CE	Rock Springs, WY	PPL	K-CW22	735,349	
							9,500	22.9CE	Rock Springs, WY	PPL	CW17		
							8,900	22.6CE	Rock Springs, WY	PPL	CW15		
							9,500	22.9CE	Rock Springs, WY	PPL	CW11		
							9,200	23.1CE	Rock Springs, WY	PPL	CW11		
					11.2	.6	9,000	26.1CE	Rock Springs, WY	PPL	CW33		
							8,900	22.6CE	Rock Springs, WY	PPL	CW1		
Big Horn Coal Co.	Big Horn #1 (S)	Armstrong Monarch	Sheridan (Sheridan)	23.8-	5.3-		9,300	115.3C	Ames, IA	CA	K-CW23	994,000	450,000
				25.7	7.2		9,900	64.4S	Denver, CO	PSCC	CW22		
							9,300	115.3S	Ames, IA	CA	CW19		
							9,400	112.1S	Marshalltown, IA	IELPC	CW5		
							10,100	63.2S	Denver, CO	PSCC	CW15		
							9,300	111.0C	Ames, IA	CA	CW14		
						.8	12,000	45.8C	Sheridan, WY	VAH	CW35		
					5.2	.5	9,600	116.6C	Ames, IA	CA	CW36		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							Wyoming (Contd.)						
Kemmerer Coal Co.	Sorensen(S)	Adaville	Lincoln (Frontier)	21.24	5.4	.5	9,600	35.2C	Kemmerer, WY	UPL	K-CW27	2,436,835	2,546,435
					3.9	.7	9,800	97.4S	Bellevue, NB	NPPD	CW36		
Rosebud Coal Sales	Rosebud(S)	#80 & 82	Carbon (Hanna)	14.2	8.5	1.0	10,500	102.9C	Waterloo, IA	IPSC	K-CW24	1,963,316	1,509,736
							10,200	108.7S	Bellevue, NB	NPPD	CW8		
							10,300	104.9S	Bellevue, NB	NPPD	CW5		
					8.0	.6	10,400	73.3CE	Fremont, NB	FDU	CW28		
					9.1	.8	10,300	65.4C	Council Bluffs, IA	IPLC	CW27		
					11.1	1.1	9,900	120.4S	Bellevue, NB	NPPD	CW27		
					8.5	1.0	10,500	102.9C	Waterloo, IA	IPSC	CW24		
							10,400	73.3CE	Fremont, NB	FDU	CW23		
							10,100	120.9S	Bellevue, NB	NPPD	CW22		
							10,400	103.7C	Waterloo, IA	IPSC	CW22		
							10,500	43.5C	Boulder, CO	PSCC	CW22		
							10,200	64.3C	Council Bluffs, IA	IPLD	CW19		
							10,400	73.7CE	Fremont, NB	FDU	CW18		
							10,400	47.6C	Denver, CO	PSCC	CW15		
							10,400	43.9C	Boulder, CO	PSCC	CW15		
							10,200	117.8S	Bellevue, NB	NPPD	CW15		
							10,300	61.9C	Council Bluffs, IA	IPLD	CW12		
							10,400	47.6C	Denver, CO	PSCC	CW11		
					8.9	.9	10,500	64.2C	Council Bluffs, IA	IPLD	CW33		

Western States (Contd.)

Company Name	Mine Name and Type	Seam Name	County (City)	% M	% A	% S	Btu	Price ¢/10^6 Btu	Destination	Utility* Serviced	Source	1974 Prod. (tons)	1973 Prod. (tons)
							Wyoming (Contd.)						
Wyodak Resources Development Corp.	Wyodak (S) (C)	Roland-Smith	Campbell (Gillette)	28.1	6.7	.4	8,000	12.0C	Wyodak, WY	BHPLC	K-CW24	738,248	727,019
					6.7	.4	8,000	23.8C	Osage, WY	BHPLC	CW24		
							8,000	41.7C	Lead, SD	BHPLC	CW23		
							7,900	23.6C	Osage, WY	BHPLC	CW22		
							7,900	10.3C	Wyodak, WY	BHPLC	CW22		
							7,900	12.4C	Wyodak, WY	BHPLC	CW9		
							7,900	39.1C	Lead, SD	BHPLC	CW9		
							7,900	23.4C	Osage, WY	BHPLC	CW9		
					5.8	.4	8,200	39.7C	Kirk, SD	BHPLC	CW33		
					5.8	.4	8,200	21.5C	Osage, WY	BHPLC	CW34		
					5.8	.4	8,200	11.1C	Wyodak, WY	BHPLC	CW34		
							7,900	22.5C	Osage, WY	BHPLC	CW8		
							7,900	11.3C	Wyodak, WY	BHPLC	CW8		
							7,900	39.3C	Lead, SD	BHPLC	CW8		
					5.8	.4	8,100	42.8C	Lead, SD	BHPLC	CW36		
					5.8	.4	8,100	12.3C	Wyodak, WY	BHPLC	CW36		
					5.8	.4	8,100	22.8C	Osage, WY	BHPLC	CW36		
Energy Development	Vanguard 1 & 2 (S)(D)	Brooks	Carbon (Hanna)	11.6-13.7	13.1	.6	9,600	75.2C	Sioux City, IA	IPSC	K-CW24	1,011,675	956,851
							10,100	74.9C	Sioux City, IA	IPSC	CW9		
							10,200	76.9C	Sioux City, IA	IPSC	CW28		
							10,200	74.7C	Sioux City, IA	IPSC	CW5		
					9.8	.4	10,500	76.1C	Salix, IA	IPSC	CW34		
					9.8	.4	10,500	79.0C	Salix, IA	IPSC	CW34		
					9.8	.4	10,500	76.1C	Salix, IA	IPSC	CW34		
					9.8	.4	10,500	77.3C	Salix, IA	IPSC	CW34		
					13.3	.4	9,700	82.9C	Salix, IA	IPSC	CW36		

*

APSC	Arizona Public Service Company
BEPC	Basin Electric Power Corporation
BHPLC	Black Hills Power and Light Company
CILC	Central Illinois Light Company
CTUC	Central Telephone and Utility Corporation
CA	City of Ames
CCS	City of Colorado Springs
CE	Commonwealth Edison
FDU	Fremont Department of Utilities
IPLD	Independence Power and Light Department
IMEC	Indiana and Michigan Electric Company
IELPC	Iowa Electric Light and Power Company
IIGEC	Iowa-Illinois Gas and Electric Company
IPLD	Iowa Power and Light Department
IPSC	Iowa Public Service Company
ISUC	Iowa Southern Utility Company
KCBPU	Kansas City Board of Public Utilities
KCPL	Kansas City Power and Light
LSDPC	Lake Superior District Power Company
LES	Lincoln Electric System
MPLC	Minnesota Power and Light Company
MPC	Minnesota Power Corporation
MDUC	Montana-Dakota Utility Company
NPPD	Nebraska Public Power District
NVPC	Nevada Power Company
NIPSCO	Northern Indiana Public Service Company
OVEC	Ohio Valley Electric Corporation
OPPD	Omaha Public Power District
OPC	Ohio Power Company
OTPC	Ottertail Power Company
PPL	Pacific Power and Light
PSCC	Public Service Company of Colorado
PSCNM	Public Service Company of New Mexico
SRP	Salt River Project
SDU	Schuyler Department of Utilities
UPA	United Power Association
UPL	Utah Power and Light
VAH	Veterans Administration Hospital (Sheridan, Wyoming)

APPENDIX C. MATHEMATICAL FORMULATION OF THE PROBLEM

This chapter describes the mathematical basis of the algorithm employed to determine the economic feasibility of coal blending. The problem is set up in the form of a nonlinear programming problem.

NETWORK ELEMENTS

Consider a simplified hypothetical system consisting of one Western coal mine, one Illinois coal mine, one blending facility, and one regional market. Transportation routes connect the allowed paths between the entities. This system is illustrated in Fig. C.1. In the figure the variables are defined as follows:

Node	Representation	Associated Cost
W	Western coal mine	The mine-mouth cost of Western coal is e_w ¢/ton.
I	Illinois coal mine	The mine-mouth cost of Illinois coal is e_i ¢/ton.
B	Blending facility	Coal is blended at a cost of b ¢/ton (b is based on operating and maintenance charges as well as capital costs amortized over the life of the facility).
M	Regional market	None.

Branch	Representation	Associated Cost
W to B	Transportation route from Western mine to blender	To transport one ton of coal from W to B costs c_{wb} ¢/ton, based on the distance from W to B.
I to B	Transportation route from Illinois mine to blender	To transport one ton of coal from I to B costs c_{ib} ¢/ton, based on distance.
W to M	Transportation route from Western mine to market	To transport one ton of coal from W to M costs c_{wm} ¢/ton, based on distance.
B to M	Transportation route from blender to market	To transport one ton of coal from B to M costs c_{bm} ¢/ton, based on distance.

One ton of Western coal delivered directly to the market accrues costs equal to:

$$P_w = e_w + c_{wm} \quad (\text{¢/ton})$$

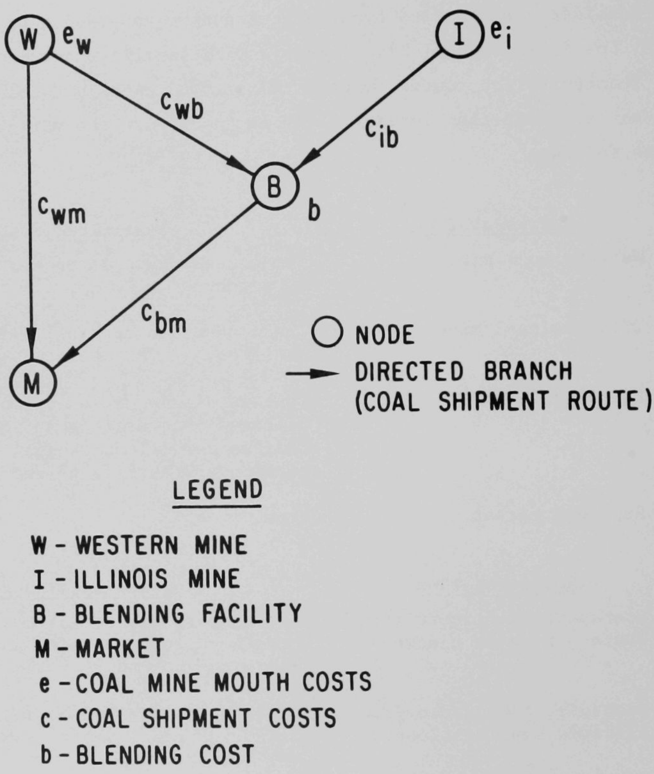

Fig. C.1. Simplified Coal Blending Network

One ton of blended coal delivered to the market accrues costs equal to:

$$P_b = f_i\,(e_i + c_{ib}) + f_w\,(e_w + c_{wb}) + b + c_{bm} \text{ (¢/ton)},$$

where

f_i = fraction of Illinois coal per ton of blended coal, and
f_w = fraction of Western coal per ton of blended coal.

Coal delivery costs P_w and P_b can be converted to costs on a million Btu basis:

$$P'_w = \frac{P_w}{B_w} \cdot \frac{10^6}{2000 \text{ lb/ton}} = 500 \cdot \frac{P_w}{B_w} \text{ (¢/}10^6\text{ Btu)},$$

where B_w is the heating value of the Western coal (Btu/lb);
and

$$P'_b = \frac{P_b}{f_i\,B_i + f_w\,B_w} \; \frac{10^6}{2000 \text{ lb/ton}} = 500 \; \frac{P_b}{f_i\,B_i + f_w\,B_w} \text{ (¢/}10^6\text{ Btu)},$$

where B_i is the heating value of the Illinois coal (Btu/lb).

If $P'_b < P'_w$, coal blending is preferred to direct shipment of Western coal.

OBJECTIVE FUNCTION

The objective of the market is to minimize its total coal expenditures. Let

X_{wb} = the yearly tonnage of Western coal shipped to the blender;
X_{wm} = the yearly tonnage of Western coal shipped directly to the market;
X_{ib} = the yearly tonnage of Illinois coal shipped to the blender; and
X_{bm} = the yearly tonnage of blended coal shipped to the market.

The market minimizes coal expenditures by minimizing the quantity:

$$\text{Minimize } (P_w \cdot X_{wm} + P_b \cdot X_{bm}) \tag{1}$$

If the supply of coal was unconstrained, then a dichotomous situation would exist. All coal utilized would consist of blended coal if $P_b' < P_w'$, or else all coal could be more cheaply supplied from Western mines if $P_w' < P_b'$. Since the supply of coal is constrained, however, a mix of blended and Western coals could possibly satisfy the market at least cost.

CONSTRAINTS

The constraints upon the system are now developed.

Mine Constraints

The mine capacity constraints are stated as

$$X_{wm} + X_{wb} \leq K_w; \tag{2}$$

$$X_{ib} \leq K_i, \tag{3}$$

where K_w and K_i are the maximum yearly coal production (in tons) of the Western and Illinois mines that can be allocated to the particular market. The constraints simply state that the quantity of coal extracted from a mine per year, which could be allocated to the market, does not exceed the ceiling on coal production established for the mine.

Blender Constraints

The blender conservation equation is stated as

$$X_{wb} + X_{ib} - X_{bm} = 0. \tag{4}$$

This constraint assures that all coal shipped to the blender is distributed to the market after blending. The SO_2 emission constraint developed in App. A assures that Western and Illinois coal will be blended in the appropriate proportions so that emission regulations are not exceeded:

$$19000 \frac{f_i \, S_i + f_w \, S_w}{f_i \, B_i + f_w \, B_w} \leq E, \tag{5}$$

where

E = SO_2 emission regulation (lb $SO_2/10^6$ Btu); and

S_i, S_w = sulfur content of the Illinois and Western coals, respectively (% by weight).

Constraint (5) can be converted to a more manageable form, as

$$19000\ (f_i\ S_i + f_w\ S_w) \leq E\ (f_i\ B_i + f_w\ B_w); \tag{5a}$$

$$19000\ f_i\ S_i + 19000\ f_w\ S_w - Ef_i\ B_i - Ef_w\ B_w \leq 0; \tag{5b}$$

$$(19000\ S_i - EB_i)\ f_i + (19000\ S_w - EB_w)\ f_w \leq 0. \tag{5c}$$

Since

$f_i = k \cdot X_{ib}$ = fraction of Illinois coal in a ton of blended coal, where k is equal to a constant

and

$f_w = k \cdot X_{wb}$ = fraction of Western coal in a ton of blended coal,

constraint (5c) can be rewritten as

$$(19000\ S_i - EB_i)\ k \cdot X_{ib} + (19000\ S_w - EB_w)\ k \cdot X_{wb} \leq 0. \tag{5d}$$

Multiplying (5d) by 1/k, the emission constraint reduces to

$$(19000\ S_i - EB_i)\ X_{ib} + (19000\ S_w - EB_w)\ X_{wb} \leq 0. \tag{5e}$$

Demand Constraints

To assure that the demand for coal in the regional market is satisfied, an additional constraint is necessary. Assuming that market demand is expressed in Btu's and is inelastic (that is, constant, unaffected by the price of the coal) the demand constraint is stated as

$$2000 \cdot B_w\ X_{wm} + 2000 \cdot (f_i\ B_i + f_w\ B_w)\ X_{bm} = D, \tag{6}$$

where D is the market demand for coal in Btu. It is implied by Eq. 6 that it is possible to satisfy the regional coal demand within the production capabilities of the mines. The condition

$$2000 \cdot B_i\ K_i + 2000 \cdot B_w\ K_w \geq D$$

must be satisfied before a feasible solution to the problem exists.

NON-LINEARITIES

Non-linearities are introduced into the objective function by the variable cost coefficients, b and e_w. Since blending costs are dependent upon the blender capacity, due to economies of scale, the following constraints are necessary to describe the piecewise nature of the blender cost data described in the main text and presented in Fig. 7:

$$
\begin{aligned}
b\ (¢/\text{ton}) = {} & 100. \text{ if } X_{bm} \leq 10^6; \\
& 75. \text{ if } 10^6 < X_{bm} \leq 4 \times 10^6; \\
& 65. \text{ if } 4 \times 10^6 < X_{bm}.
\end{aligned} \tag{7}
$$

It was also assumed in the study that the unit mine-mouth cost of Western coal increases linearly with increases in the quantities of coal produced. Let e_{ow} be the unit mine-mouth cost (¢/ton) of Western coal at current mine capacity. Then the unit mine-mouth cost due to increasing the production of the mine by $(X_{wm} + X_{wb})$ tons is given by:

$$e_w = e_{ow} + \overline{E}\ (X_{wm} + X_{wb}), \tag{8}$$

where $\overline{E}$ is the elasticity of Western coal mine-mouth prices. ($\overline{E} = \%\Delta(¢/\text{ton})/\%\Delta(\text{tons})$, that is, the ratio of the percent increase in the unit mine-mouth cost to the percent increase in annual mine production.)

The problem then becomes one of minimizing the objective function (Eqs. 1, 7, and 8), while satisfying constraints 2, 3, 4, 5e, and 6.

EXPANDED PROBLEM FORMULATION

The above problem formulation is a simplified example of the problem addressed in this study. The actual problem, considering 30 Western mines, 24 Illinois mines, 5 regional markets, and 5 blending locations can be set up in a nonlinear programming formulation analogous to the above problem formulation. However, its dimensionality increases rapidly as more elements are added. If all of the constraints were stated explicitly, at least 3000 expressions would have to be constructed. Furthermore, a computerized nonlinear programming package probably could not solve for an optimal solution in a cost-effective manner. For these reasons a heuristic method was employed to arrive at a near-optimal solution that would satisfy the constraints. Although the heuristic method provided a solution to the problem, the constraints did not have to be stated explicitly. The heuristic employed is a variation of the well-known least-cost method, and its use in this study is explained in the text in Chapter 5.5. Although the least-cost method does not always give the optimal solution, a near-optimal solution, which satisfies the constraints, is assured.

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